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Orkustofnun, Grensasvegur 9,
IS-108 Reykjavik, Iceland

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QUANTIFYING FEED ZONE CONTRIBUTIONS FROM PRESSURE-TEMPERATURE-SPINNER DATA AND PRESSURE TRANSIENT ANALYSIS USING WELLTESTER

Normann M. Buscato
Energy Development Corporation – EDC
38/F One Corporate Centre Building
Julia Vargas corner Meralco Avenue
Ortigas Center, Pasig City, 1605
PHILIPPINES
buscato.nm@energy.com.ph

ABSTRACT

Understanding the reservoir in a geothermal system is a key issue in sustainable production in a geothermal power plant. Modelling the pressure change during changes in injection or production gives a good view on how the reservoir responds. Quantifying the feed zone contribution in a flowing geothermal well is additional information useful in planning production in a power plant. The WellTester software is under development at Iceland GeoSurvey (ÍSOR) and is used to do the modelling of pressure transient analysis. The software was used to analyse the pressure response caused by changes in injection in well TW-4D, a production well in Bacman Geothermal Production Field in the Philippines, which is a part of a well completion test. The results are compared to the results from software called Sapphire. The results from both softwares are similar for the skin, injectivity index and permeability thickness. In addition, 3 production wells in the Philippines were studied with respect to flow capacity, namely well MY-1D in Northern Negros Production Field, well Pal-30D and well TW-4D in Bacman Geothermal Production Field, where spinner logs were used for estimating feed point contributions in a geothermal well. The results of the calculation of the flow capacity are estimated values for each feed zone for each well.

1. INTRODUCTION

Drilling into the crust gives an opportunity to study the physical properties of rock formations surrounding the wellbore (Steingrímsson, 2011). After the drilling operation, a well completion program is conducted in order to gather information on the feed zones of the well and the hydrological parameters of the reservoir. A completion program consists of pressure, temperature, spinner surveys after drilling to test the new geothermal well in order to gain information on the reservoir and the well being tested. Well logs are a part of the completion test as well as step rate test where the pressure response to a change in the injection rate is measured often for several hours for each step. Well logging using the Pressure-Temperature-Spinner (PTS) tool is commonly used to provide information in a wellbore from the casing head flange (CHF) down to the bottom of the well.

This paper consists of two different analyses using data from the post drilling and post acidizing completion test: 1) Flow capacity studies and calculations from PTS logs. Flow capacity estimation of a feed zone is important for understanding the possibilities and function of a wellbore. A spinner connected with the Temperature-Pressure tool is necessary for flow measurements in the wellbore and determining fluid inflow or outflow from the reservoir. The basic theory and the calibration of the spinner tool are discussed in the background section. The calibration of the spinner here is done with data from the field survey, if calibration data from the laboratory are unavailable. 2) Pressure transient analysis or injection or step test analysis using PTS data, where pressure responses caused by changes in injection are analysed. Pressure transient analysis is conducted to characterize the hydrological parameters of a reservoir. An injection step test is usually done at the end of drilling at a selected depth in the borehole. The test most commonly used is to apply different injection rates in steps while observing the pressure changes in the wellbore. The pressure data versus time as well as the injection rate are used in modelling to determine the physical properties of the well and the reservoir, e.g. the skin of the well and the storativity and transmissivity of the reservoir. The modelling of the data in this work was done using WellTester, a program developed at ÍSOR (Júlíusson et al., 2008). The basic theory and principle behind WellTester is discussed in the background section.

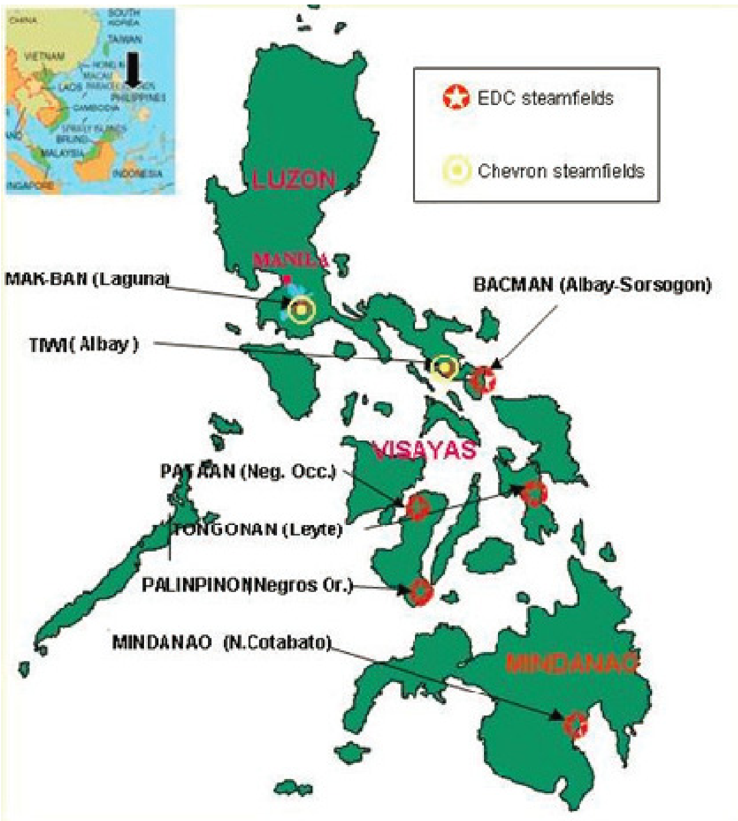

FIGURE 1: The Philippines: Well MY-1D in Pataan Negros Occiental, and TW-4D and Pal-30D in Bacman geothermal field

Data from three wells in the Philippines were used in the study (Figure 1). PTS logs or Pressure-Temperature-Spinner logs and PTS readings during some hours at a fixed location in a well are frequently used in the Philippines in conducting well completion tests and flow surveys. In this paper, the well completion test data on well TW-4D from Bacman geothermal production field situated in Albay Sorsogon area on Luzon (Figure 1) were used in a pressure transient analysis. The well was subjected to a completion test after post drilling enhancement activity to improve and stimulate the wellbore capacity. The result of the well test analysis using WellTester was also compared to an analysis using the Sapphire program. On the other hand, three production wells, TW-4D and Pal-30D from Bacman geothermal field in Albay Sorsogon (Figure 1) and MY-1D from the Northern Negros geothermal field located in Pataan Negros Occidental in the Visayas area (Figure 1), were used in flow capacity calculations. The data from the test of the three wells were used together to calibrate the spinner response in order to calculate the flow capacity of each feed zone in each of the wells. The data will give the approximate contribution from each feed zone to better understand the reservoir.

The aim of the project is twofold:

1) To know the basic principles and theory in Pressure Transient Analysis and how to model data to determine hydrological properties of a geothermal reservoir; and
2) To calculate flow capacity of individual feed points of a geothermal well.

2. BACKGROUND

After drilling a geothermal well, a wellbore completion test is conducted which consists of an injection test and PTS logs up and down the well with several injections and several speeds of the logging tool. The objective of the test is to determine the hydrological properties of the reservoir and the fluid flow in the well. The test is designed to identify the possible or potential feed zones in the well, and to provide estimates on the transmissivity, storativity, and skin of the reservoir system and the well. The pressure transient test analysis is discussed in Section 2.3. Calculating the well flow capacity is discussed in Section 2.2. The test is usually done using an electronic tool with temperature and pressure transducers as well as a spinner (flow velocity indicator).

A logging truck is needed at the drill site with 3 technicians and an engineer to carry out the logging operation. The survey is conducted in a closed system. A lubricator and pressure control equipment such as blow-out-preventers are needed to control wellhead pressure while implementing a flow survey. There are two types of Pressure-Temperature-Spinner tools, a mechanical tool and an electronic tool. The electronic tools are of two kinds, either providing real-time logs or a memory tool log (Hagen Hole, 2008) from which the data can be read when the tool has arrived back to the surface.
The PTS tool, either a mechanical or an electronic tool, is suitable for production and injection testing or shut-in surveys in geothermal wells.

2.1 Measurements - procedure

In the Philippines, well completion test are conducted with increasing water injection in steps from the minimum rate of the rig pump to the maximum capacity of the water supply; the logs are registered at different cable line speeds of lowering or pulling up the PTS tool. In between, the pressure response in the step test is measured for different injection rates, first increasing but decreasing the injection in the final step. The usual flow rates used in the Philippines are 11 l/s (4 Barrels Per Minute (BPM)), 22 (8), 33 (12), and 44 l/s (16 BPM) and finally decreased to 11 l/s for the last step in the injection test. However, the injection rate can be modified by the reservoir engineer to adjust to the actual conditions of the wellbore and the water available for injection.

The information obtained from running the tool at least at three different cable line speeds is used in quantifying or estimating the feed point contribution according to the spinner response. Temperature, pressure and spinner logs are measured as a function of depth as well as a function of time.

Pressure data from a post enhancement completion test in well TW-4D were analysed using WellTester. To better understand the procedure, a short description of the well follows. Well TW-4D is a vertical well with a total depth of 2592 m. The production casing reaches down to 1976 m and a slotted liner down to 2592 m. The production casing was perforated at several depth intervals to access mass flow from the cased off permeable zones. The uppermost perforations are at 1420 m depth. The TW-4D well completion test was conducted using a PTS tool. The test program includes a pumping test (injectivity test) and a pressure fall-off test. This was completed while pumping water at four different rates 37 l/s (14 BPM), 47 (17.8), 57 (21.8), and 26.4 l/s (9.9 BPM) for the pressure fall off test (PFO), i.e. the last step of the test. The survey procedure is as follows:

1. Before starting the well completion test program, surface test the PTS tool to ensure the tool is working properly. Rig up the tool and start lowering it inside the wellbore.
2. While pumping water during the first step rate, log the well at three (3) different logging speeds. Conduct stationary logs at the depths identified by the Reservoir Engineer.
3. Set the PTS tool at the injectivity setting depth and record pressure readings for the next two rates (14 BPM and 17.8 BPM). The tool setting depth is where the tool stays during injection of different flow rates in the steps test.

4. Increase the pump rate to 57 l/s (21.8 BPM) and allow pressure readings for a few minutes.
5. Log the well at three logging speeds.
6. After completing the logging procedure for the last step rate (57 l/s), conduct a pressure fall-off test (PFO) by setting the tool at the injectivity setting depth. Record the base data and lower the pump rate to 26.4 l/s (9.9 BPM) for at least 6-8 hours.
7. After completing the PFO test, pull out the PTS tool. If pumping is stopped completely, record the log up from the maximum allowable depth to determine the water level while the well is static.
8. Rig down the PTS tool and dismount the equipment after ensuring that all of the PTS data is in the computer.

A sample plot for the TW-4D well completion test, conducted after post drilling activity and showing the temperature-pressure-spinner response against depth with an injection rate of 13.4 l/s (5 BPM), is shown in Figure 2, where the upward logs for three line speeds, 20, 30 and 40 m/min, are shown. The data are then used for computing the capacity of each feed zone identified on the spinner and temperature logs.

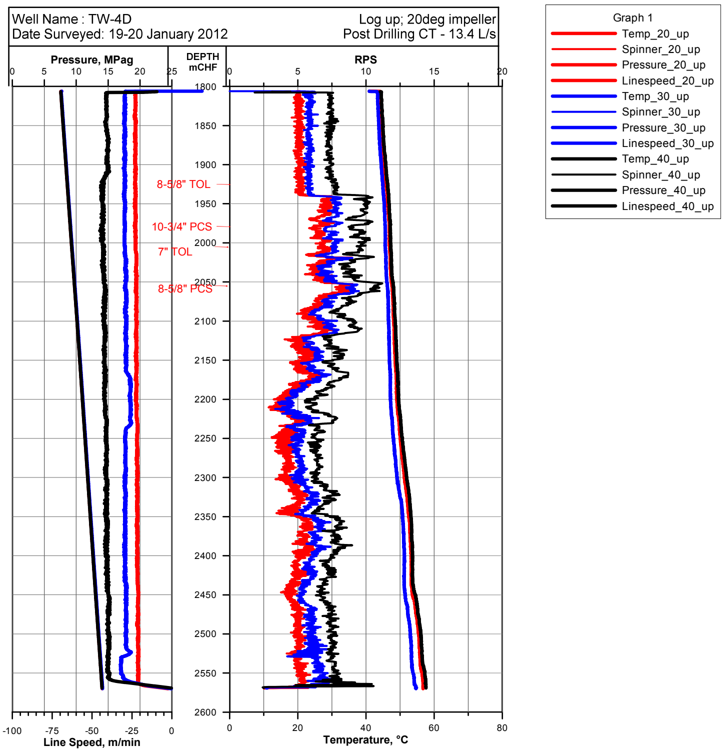

FIGURE 2: Well TW-4D Pressure-Temperature-Spinner logs as a function of depth during post drilling well completion test 19-20 Jan 2012 while injecting 13.4 l/s

2.2 Flow capacity determination

Flow capacity measurement in the wellbore is conducted to locate feed zones and to evaluate how much each feed zone is contributing during injection/production. This is done in the completion test. An impeller is the spinner in the PTS tool. The impeller´s (spinner) response is used to estimate the flow for each identified feed point in the wellbore. The fluid flow causes the impeller to turn (either clockwise or counter-clockwise), with the frequency being proportional to the relative velocity between the tool and the fluid in the well. The spinner is assumed to measure a representative fluid velocity. The tool must be centralized, especially if the wellbore is deviated, in order to have a representative measurement value (Grant and Bixley, 2011).

2.2.1 Spinner calibration

Calculating the flow rate of each feed zone from a spinner log is important, in order to estimate the contribution to the total flow in the well. To quantify the flow rate, spinner data are used to determine fluid velocity. Calibration of the spinner response relates the impeller frequency to the fluid velocity and gives a reliable background for the fluid velocity calculations. The relationship is called the tool´s response curve (Maceda et al., 1997).

Calibration of the spinner can be done in a laboratory or in an actual geothermal well. The measurements are selected where all the parameters needed for the calibration are known, e.g. diameter of the pipe, fluid flow rate and the spinner characteristics such as impeller type, shaft, and bearing. The spinner tool is set in a specific location inside the casing while changing the flow rate in the pipe. The rotation of

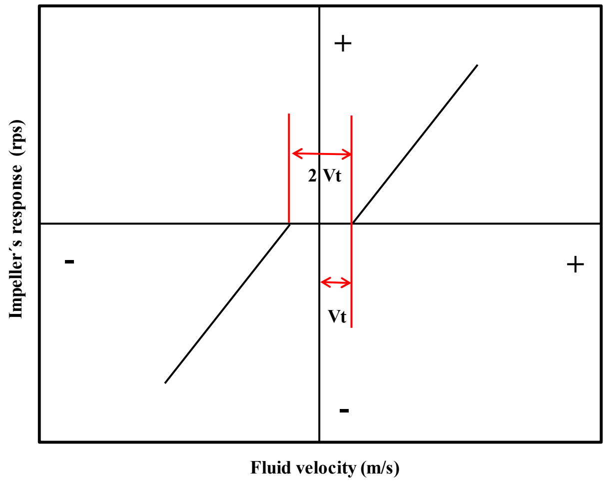

FIGURE 3: Typical flow meter or spinner response curve, showing the threshold velocity (Vt) and relationship between the fluid velocity and the spinner's rotation

the spinner is measured and plotted to get the tool´s response curve. A typical response curve is shown in Figure 3, showing the plot of the impeller (RPS) (Rotations Per Second) against the changing fluid velocities with the spinner stationary in moving fluid. If water flow is going upward, the impeller will only start to rotate when the fluid velocity exceeds the threshold velocity and will continue to increase as the fluid velocity increases. The same applies when the water is going downward, the impeller will only start to rotate in the opposite direction when it exceeds the threshold velocity and will continue to increase as the fluid velocity increases.

The fluid velocity necessary to start the rotation of the impeller is denoted as Vt (threshold velocity). It depends on the type of impeller used.

2.2.2 Determining Vt (threshold velocity) using three spinner cable velocities

If calibration of the spinner is not available from the laboratory, a similar response curve can be generated by taking measurements in a well of at least three constant spinner velocities while injecting a constant flow rate into the well. The relationship between cable velocities to spinner response curve is shown in Figure 4. This is not the true response curve but rather a similar curve to a typical flow meter response curve. The plot is generated from well completion test actual spinner data wherein four flow rates were used. The spinner tool was logged with three different line speeds in each stable flow rate. The data was then plotted to generate two lines of similar slope, one for the positive rotation, the other one for the opposite direction of rotation.

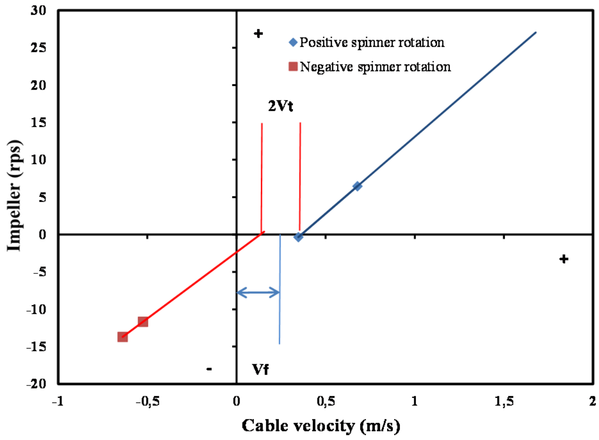

FIGURE 4: Well TW-4D – RPS against cable velocity during injection

The impeller's spinner will only rotate when force produced by the fluid velocity exceeds the friction on the bearing of the impeller´s shaft. A bearing is any machine element that constrains the relative motion between two or more parts to only the desired type of motion. Typically, this is to allow and promote free rotation around a fixed axis or free linear movement; it may also be to prevent any motion which is the case in a spinner assembly.

It is necessary to know the threshold velocity (Vt) for each impeller type. Each impeller type has different attributes such as the angle of the blades, the material used, and the friction of the bearing that has an impact in calculating the threshold velocity. A tool response curve using three spinner cable velocities in TW-4D (located in Bacman geothermal field in the Philippines) is shown in Figure 4. The plot was generated from well logging data while the spinner passed along the wellbore at various constant velocities and a stable flow rate (13, 26, 39 l/s), showing the spinner response as a function of cable velocity.

In Figure 4, the two lines are based on logs of two different directions (upward and downward log) during injection with the spinner rotating both in a clockwise and a counter-clockwise direction (positive and negative RPS, respectively). The difference between the x-intercepts of the two lines is twice the threshold velocity. The spinner only starts to rotate when the relative fluid velocity exceeds the threshold velocity of the impeller. If the tool is stationary during injection, the rotation is defined as negative, but on the other hand when the tool is moving down without any injection, the rotation is defined as positive (see Figures 3 and 4). Generally, as the cable velocity increases, the spinner rotation increases.

2.2.3 Determining fluid velocity

The response curve, as shown in Figure 4, where the cable velocity (V_c) is on the X-axis and spinner response (RPS) on the Y-axis, for a station fitted with linear regression is defined by the equation:

$$RPS = a + (m \times V_c) \tag{1}$$

where RPS = Impeller response (RPS);
a = Intersection with the Y-axis, where x=0, (RPS);
m = Slope of regression (-); and
V_c = Cable velocity (m/s).

As the impeller response reaches zero, Equation 1 can be expressed as:

$$X_{int} = V_c = -\frac{a}{m} \tag{2}$$

where X_{int} = Intersection with the X-axis where y=0, (m/s).

Using the slope of the negative values, the fluid velocity denoted as V_f as shown in Figure 4 can be computed as:

$$V_f = X_{int} + V_t \tag{3}$$

In theory, the stationary reading of the spinner tool denoted as RPS_0 is equal to the computed y-axis intercept a. Therefore, Equation 3 can be rewritten as:

$$V_f = -\frac{RPS_0}{m} + V_t = -\frac{a}{m} + V_t \tag{4}$$

Grant and Bixley (2011) described a method to find the fluid velocity in the following way:

- Check spinner frequency data for null values (impeller may be stuck in wellbore debris);
- Sort data by depth (choose depth where up and down profile is present); and
- Check cross plots of frequency versus cable speed at several depths to check how many data points are needed to obtained a reliable cross plot.

This method will give a rational profile, but extra care should be taken in using the spinner data. Checking for the slope of the profile is a way to ensure a reasonable plot.

2.2.4 Fluid flow calculation

Inside the wellbore, the spinner measures the fluid velocity in the centre of the well, as shown in Figure 5, for both laminar and turbulent flow. To calculate the flow rate, the average of the fluid velocity across the well is used. The flow of water inside the wellbore is either laminar or turbulent. A correction factor is applied to compute the average velocities for both the laminar and turbulent flows of the fluid. The correction factor is empirically derived from Reynold's number of the flow (Atlas Wireline Services, 1982; Maceda et al., 1997).

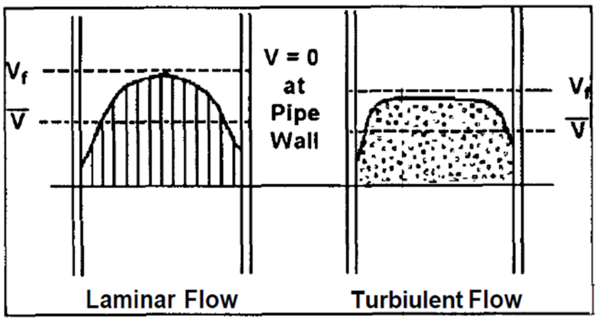

FIGURE 5: Fluid velocity profiles for laminar and turbulent flows (Atlas Wireline Services, 1982; Maceda et al., 1997)

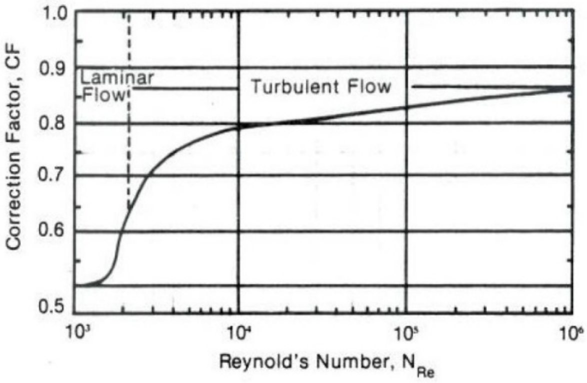

FIGURE 6: Reynold's number correction factor (Atlas Wireline Services, 1982)

For turbulent flow inside the wellbore, the correction factor is 0.83. In Figure 6, the value can be estimated using the plot of the correction factor for Reynold's number. The difference is emphasized clearly in the laminar flow, as shown in Figure 5. In this paper, the correction factor 0.83 for turbulent flow is used. It is assumed that the water flows for all wells under study follow a turbulent flow for simplicity of calculation.

To check if the water flow is laminar or turbulent flow, a widely used index for checking for turbulence is Reynold's Number, N_{Re},

$$N_{Re} = \frac{\rho V D}{\mu} \tag{5}$$

where ρ = Fluid density (kg/m^3);
μ = Fluid viscosity (kg/(m·s));
V = Average fluid velocity (m/s);
D = Inside pipe diameter (m).

For N_{Re} greater or equal to 3000 the flow is turbulent, and laminar flow if it is less than or equal to 2000. N_{Re} values between 2000 and 3000 signify either laminar or turbulent flow, depending on well conditions (Maceda et al., 1997).

The corrected velocity can be expressed as:

$$V_{fc} = V_f \times correction\ factor \tag{6}$$

To compute for the volumetric flow rate, Q:

$$Q = V_{fc} \times A \tag{7}$$

where A = The cross-sectional area of the borehole (m^2), where the measurement is done.

The volumetric flow rate can be converted to mass flow (kg/s) by multiplying it with the density of water ρ.

The calibration of the flow measurement varies depending on the well diameter. The response curve on each section of the well with varying diameter should be established and used in the computation. The well profile should be studied, and if a caliper survey is available it should be incorporated into the analysis of the spinner.

2.3 Well testing (pressure transient test or well test analysis)

Understanding the properties of a hydrological reservoir and its conditions is important. Well testing is a way to answer questions on the properties and conditions of the reservoir surrounding a well. In well testing, the pressure response of the reservoir is tested and monitored during injection into a well or production from a well, changed in steps. This is done at a selected depth depending on the main feed zones in the wellbore or at a nearby wellbore. The conditions and properties of the well and the reservoir can be evaluated in an appropriate model. During well testing interpretation, important parameters such as the permeability, thickness and storativity of the reservoir are determined as well as the skin and wellbore storage.

Well test analysis, in many cases, is synonymous with pressure transient analysis. The pressure transient is caused by a change in production or the injection of fluids; hence, the flow rate transient is termed as input and the pressure transient as output (Horne, 1995).

WellTester is an ÍSOR software (Júlíusson et al., 2008) used to analyse pressure response during well testing, and is used in the analysis which is a part of this report. The background for the analysis is introduced in the following pages, but the practical aspects of WellTester will be introduced in Section 3.2 with the data processing and modelling of an injection step test in the Philippines.

2.3.1 Pressure diffusion equation

In well testing, the basic equation is the pressure diffusion equation. It underlines the importance of the diffusion process in well test interpretation and stresses the importance of the hydraulic diffusivity parameter (Horne, 1995). A commonly used solution of the pressure diffusion equation is the Theis solution or the line source solution. Three main equations are used in the derivation of the pressure diffusion equation (Jónsson, 2012):

The principle of mass conservation which states: For any arbitrary volume element, the mass entering the element minus the mass leaving the element is equal to the rate of change of mass inside the element, and shown in polar coordinates as:

$Mass_{in} - Mass_{out} = rate\ of\ change\ in\ mass$

$$\left(\rho Q + \frac{\partial(\rho Q)}{\partial r}\,dr\right) - \rho Q = 2\pi r dr\,\frac{\partial\,(\varphi\rho h)}{\partial t} \tag{8}$$

or

$$\frac{\partial(\rho Q)}{\partial r} = 2\pi r h\,\frac{\partial(\varphi\rho)}{\partial t} \tag{9}$$

where r = Radial distance from the center of the well (m);
t = Time (s); and
φ = Porosity (no unit).

Darcy´s law, which presents a simple proportional relationship between the instantaneous discharge rate (Q) through a porous medium, the viscosity of the fluid and the pressure drop over a given distance, as is for the radial model shown in Figure 7:

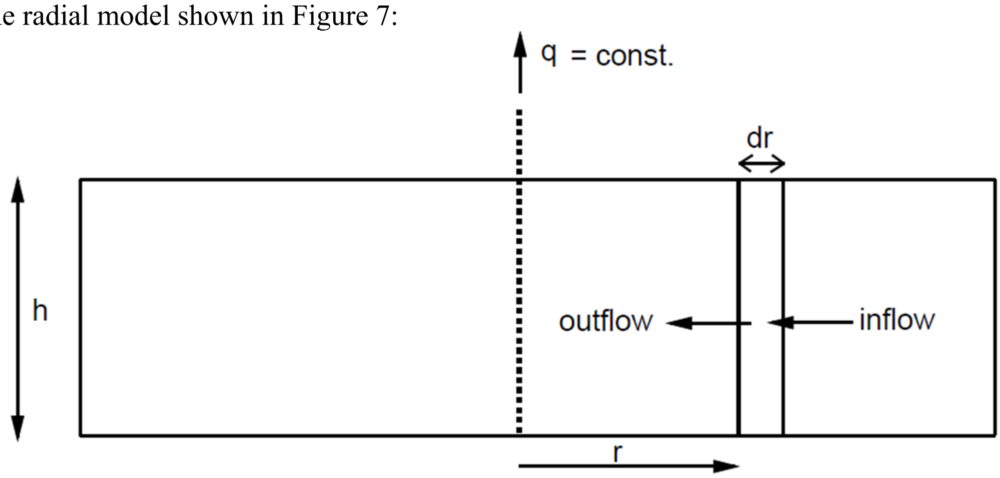

FIGURE 7: Radial flow of a single-phase fluid in a homogeneous medium (Hjartarson, 1999)

$$Q = 2\pi r h \frac{k}{\mu}\frac{\partial P}{\partial r} \tag{10}$$

where Q = Volumetric flow rate (m^3/s);
h = Reservoir thickness (m);
k = Formation permeability (m^2);
P = Pressure at a distance, r from the borehole (Pa);
r = Radial distance (m); and
μ = Dynamic viscosity of fluid (Pa·s).

Compressibility, which is a measure of the relative volume change of a fluid or solid as a response to a pressure change. This covers the compressibility of the rock, fluid and the total compressibility of the system.

$$c_w = \frac{1}{\rho}\frac{\partial \rho}{\partial P}\ , fluid\ compressibility \tag{11}$$

$$c_r = \frac{1}{1-\varphi}\frac{\partial \varphi}{\partial P}\ , rock\ compressibility \tag{12}$$

$$c_t = \varphi c_w + (1-\varphi)c_r\ , total\ compressibilty \tag{13}$$

where c_r = Rock compressibility (Pa^{-1});
c_w = Fluid compressibility (Pa^{-1});
c_t = Total compressibility (Pa^{-1});
ρ = Density of fluid (kg/m^3);
φ = Porosity (no unit); and
P = Pressure (Pa).

In addition, assumptions are needed on the reservoir and the flow:

- Homogeneous and isotropic reservoir;
- Isothermal conditions;
- Uniform thickness of reservoir, *h;*
- Single-phase flow;
- Small pressure gradients;
- Constant porosity;
- Horizontal radial flow;
- Darcy's law applies;
- Small and constant compressibility;
- Constant fluid viscosity; and
- Constant permeability.

Based on these assumptions, the pressure diffusion equation can be reduced to:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(\frac{r\partial P(r,t)}{\partial r}\right) = \frac{\mu c_t}{k}\left(\frac{\partial P(r,t)}{\partial t}\right) = \frac{S}{T}\frac{\partial P(r,t)}{\partial t} \tag{14}$$

or

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{r}\frac{\partial P}{\partial r} = \frac{\mu c_t}{k}\frac{\partial P}{\partial t} = \frac{S}{T}\frac{\partial P}{\partial t} \tag{15}$$

$$S = c_t\, h \tag{16}$$

$$T = \frac{kh}{\mu} \tag{17}$$

where S = Storativity (kg/m^3 Pa);
T = Transmissivity (m^3/Pa s);
c_t = Total compressibility (Pa^{-1});
h = Effective reservoir thickness (m);
k = Permeability of the rock (m^2);
μ = Dynamic viscosity of the fluid (Pa s);
$P(r,t)$ = Reservoir pressure at a distance r and time t (Pa);
t = Time (s); and
r = Distance from the borehole (m).

2.3.2 Theis solution

To obtain a complete mathematical description of fluid flow in a porous medium, initial and boundary conditions must be set for the flow equation. The initial conditions define the pressure state in the reservoir prior to the test while the boundary conditions refer to the effect of the environment on the flow process.

Initial conditions

$$P(r,t) = P_i \; for \; t = 0 \, ; r > 0 \tag{18}$$

where P_i = Initial reservoir pressure, Pa

Boundary conditions

$$\lim_{r \to \infty} P\,(r,t) = P_i \; for \;\; r \to \infty \, ; t > 0 \tag{19}$$

$$2\pi r h \frac{k}{\mu}\frac{\partial P}{\partial r} \to Q \; for \; r \to 0, for \; t > 0 \tag{20}$$

The outer boundary condition (Equation 19) accounts for the constant pressure at infinity while the inner boundary (Equation 20) is a flow condition through the well which has a radius close to zero compared to the infinite reservoir. The solution to this problem is known as the Theis solution and is described as:

$$P(r,t) = P_i - \frac{Q\mu}{4\pi k h} W\left(\frac{\mu c_t r^2}{4kt}\right) = P_i - \frac{Q}{4\pi T} W\left(\frac{S r^2}{4Tt}\right) \tag{21}$$

where *W(x)* is the exponential integral function:

$$W(x) = -E_i(-x) = \int_x^\infty \frac{e^{-u}}{u}\, du \tag{22}$$

Tables for the exponential integral function can be found in mathematical handbooks.

In the case of drawdown, this becomes:

$$\Delta H = H - H_o = -\frac{Q}{4\pi\rho g T} W\left(\frac{S r^2}{4Tt}\right) \tag{23}$$

For small values of $x = \frac{Sr^2}{4Tt}$ we can use:

$$W(x) \approx -\ln(x) - \gamma \;\; for \; x < 0.01 \tag{24}$$

where γ is the Euler constant, γ = 0.5772.

For

$$t > 25\frac{\mu C_t r^2}{k} = 25\,\frac{Sr^2}{T} \tag{25}$$

i.e. for small *r* or large *t*, the Theis solution can be rewritten as:

$$P(r,t) = P_i + \frac{2.303Q}{4\pi T}\left[\log\left(\frac{Sr^2}{4Tt}\right) + \frac{\gamma}{2.303}\right] \tag{26}$$

or

$$P(r,t) = P_i - \frac{2.303Q}{4\pi T}\log\left(\frac{2.246T}{Sr^2}\,t\right) \tag{27}$$

Equation 27 is the most used equation in well test analysis and describes pressure draw-down at a distance *r* at a time *t* when producing at a constant rate *Q* in a radial flow of a single-phase fluid in a homogeneous reservoir model.

2.3.3 Semilog analysis

By monitoring pressure changes with time, it is possible to fit the observed pressure history to the theory and identify two important parameter groups, the permeability thickness (*kh*) and storativity ($c_t h$). The permeability describes the medium´s ability to transmit fluid, and the storativity describes the medium´s ability to store fluid. By rearranging Equation 27 to the form $\Delta P = \alpha + m \log t$, the pressure change can be plotted versus time on a semi-logarithmic graph, where *t* is on a logarithmic scale, and a straight line is obtained.

$$\Delta P = P_i - P(r,t) = \frac{2.303\,Q}{4\pi T}log\left(\frac{2.246T}{Sr^2}\right) + \frac{2.303\,Q}{4\pi T}log(t) \tag{27}$$

The line is characterized by slope m and an intercept, α, with the Y-axis, where:

$$\alpha = \frac{2.303\,Q}{4\pi T}\log\left(\frac{2.246T}{Sr^2}\right);\ m = \frac{2.303Q}{4\pi T} = \frac{2.303\mu Q}{4\pi kh} \tag{28}$$

By determining m, the transmissivity of the reservoir can be estimated by:

$$T = \frac{kh}{\mu} = \frac{2.303Q}{4\pi m} \tag{29}$$

The permeability thickness can be written as:

$$kh = \frac{2.303Q\mu}{4\pi m} \tag{30}$$

Equation 27 can be rewritten as:

$$\Delta P = P_i - P(r,t) = \frac{2.303\,Q}{4\pi T}\log\left(\frac{2.246T}{Sr^2}\,t\right) \tag{31}$$

or

$$10^{\Delta P} = 10^m\left(\frac{2.246T}{Sr^2}\,t\right) \tag{32}$$

Arranging to find storativity, the equation becomes:

$$S = c_t h = 2.246\left(\frac{kh}{\mu}\right)\left(\frac{t}{r^2}\right)10^{-\frac{\Delta P}{m}} = 2.246T\left(\frac{t}{r^2}\right)10^{-\frac{\Delta P}{m}} \tag{33}$$

2.3.4 Wellbore storage and skin factor

Welltest analysis is the interpretation of a pressure response of the reservoir to a given change in the injection rate. For many well tests conducted, controlling the flow rate can only be done in the wellhead valve or flow line. The injection may be at constant rate at the wellhead. The transient flow inside the wellbore itself may mean that the flow rate from the reservoir into the wellbore may not be constant at all. This is known as the wellbore storage (Horne, 1995).

The wellbore storage coefficient is a parameter used to quantify this effect and can be expressed as:

$$C = \frac{V}{\Delta P} \tag{34}$$

where C = Volume of fluid that the wellbore itself will produce due to a unit drop in pressure;
V = Volume produced; and
ΔP = Pressure drop.

Pressure propagation does not take place uniformly throughout the reservoir. The reason behind this is that it is affected by local heterogeneities. During drilling, appropriate pressure control is not always the case, thus external fluids (such as mud or cement) enter the original formation around the well and create a zone with lower permeability. Methods like acid stimulation and hydro-fracturing are often programmed to improve the permeable zone during production. Such zones are called skin zones (Figure 8). When the skin is negative, i.e. in a damaged well shown in Figure 8, the skin creates an additional pressure drop near the wellbore in addition to the normal reservoir pressure change caused by production (Horne, 1995). When the skin is negative, it reduces the drawdown.

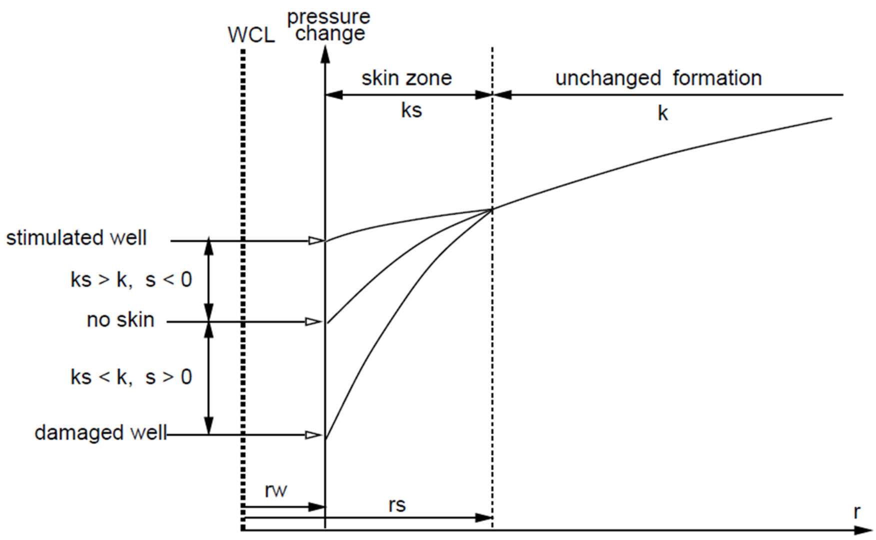

FIGURE 8: Pressure changes in the vicinity of a well due to a skin effect
(WCL = well centre line; r_w = well radius; r_s = radius of skin) (Hjartarson, 1999)

The skin (s, dimensionless) causes additional pressure change ΔP_s in the near vicinity of the well and can be expressed as:

$$\Delta P_s = \frac{Q\mu}{2\pi kh} \cdot s = \frac{Q}{2\pi T} \cdot s \tag{35}$$

In addition to the pressure change caused by the flow in the formation, the drawdown equation becomes:

$$\Delta P_{tot} = P_i - P(r_w, t) \approx \frac{2.303Q}{4\pi T}\left[\log(t) + log\left(\frac{T}{Sr_w^2}\right) + 0.3514 + 0.8686\, s\right] \tag{36}$$

where the last term is the drawdown due to the skin.

The skin effect does not change the evaluation of permeability thickness in a semilog analysis; however, it does affect the storativity evaluation. Equation 33 must be changed to:

$$Se^{-2s} = c_t he^{-2s} = 2.246T\left(\frac{t}{{r_w}^2}\right)10^{-\frac{\Delta P_{tot}}{m}} \tag{37}$$

3. PTS DATA PROCESSING (PRESSURE-TEMPERATURE-SPINNER DATA)

3.1 Flow measurement

In this chapter, three geothermal production wells in Philippines are under study. Two of the wells, namely TW-4D and Pal-30D, are both located in the Bacman Geothermal Production Field (BGPF). The field is situated in the Luzon area of the country (Figure 1). The third well, MY-1D, is located in the Northern Negros Geothermal Production Field (NNGPF) situated in the Visayas region. The three wells were subjected to well completion tests (injection tests) after drilling and post enhancement activities.

3.1.1 Data processing and threshold velocity calculation

Quantifying or estimating the different feed zone contributions in a wellbore is an important aspect in understanding the characteristics of a geothermal well. Each well was analysed individually and each threshold velocity (Vt) was determined, as discussed in the background chapter. Information on the calibration of the spinner tool from a laboratory was not available. The PTS tool used in all of the surveys is from a 3rd party contractor, SDI (Scientific Drilling Inc.), since the Energy Development Corporation (EDC) does not currently own a PTS tool.

Calibration of each impeller type was taken into account since each type has its own characteristics, pitch, and symmetry of the impeller. Each type of spinner has its own set of parameters, i.e. the number of rotations depends on the angle of the spinner blade and the friction created on each bearing type. If calibration of the spinner from a laboratory is available, one good practice is to counter check the parameters of the calibration.

In the determination of the threshold velocity (Vt), the different line speeds in the upward logs or the different line speeds in the downward logs were used. The sample depth selected is inside the casing where the diameter is known and, therefore, the fluid velocity can be calculated using the injection rate. An average of 30 data points on the selected depth was taken. Steps to consider in determining the threshold velocity for each well include:

- Choose a depth inside the production casing where the diameter is known and spinner data with at least 2-3 cable line speeds are available (either upward logs or downward logs). This is to calculate the total flow rate of the injected fluid.
- Analyse caliper data of the well if available. The spinner response is highly sensitive to change in diameter.
- Take an average of about 30 data sets per depth location, to get a relative value of the response of the spinner. Eliminate data where the noise is too high, e.g. a spike in the data caused by clogging with debris. In some cases, it is better to use the median (e.g. with spiky data).
- Plot the average of RPS against each line speed, Vc, (either in the upward or downward log).
- When these data are plotted, check if the lines have the same slope. If not, corrections need to be made.
- Determine the cable velocity, Vc, where the impeller's rotation is 0 rps, i.e. the x-intercept of each line by using Equation 2.
- Use Equation 4 to calculate the average Vf (<Vf>) by getting the y-intercept of the line (RPS_0), i.e. where Vc is 0.
- Calculate the average fluid velocity (Vi), i.e. the injected fluid velocity in the casing based on the injection rate and casing diameter.
- Divide Vi (average fluid velocity) with the correction factor to get the corrected <Vf>.
- Use Equation 3 to determine the threshold velocity.
- If the threshold velocities for both flow rates are not equal, take the average of the two values.

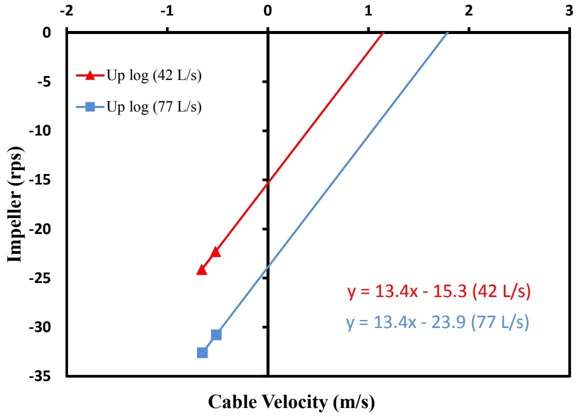

FIGURE 9: Well MY-1D showing RPS (rev. per second) of the spinner against cable velocity

The calibration curves for the three production wells, MY-1D, Pal-30D and TW-4D, are shown in Figures 9-11 and the calculated threshold velocities are listed in Tables 1-3, respectively. The data used in calculating the threshold velocity are either only from the downward logs or only from the upward logs. In each graph, choose the lines with similar slope as shown in Figures 9-11. In Tables 1-3, the spinner response for each line speed is tabulated as well as the computed threshold velocity for each flow rate. The average threshold velocity for each flow rate is determined and is used in the calculation for the flow contribution of each feed zone.

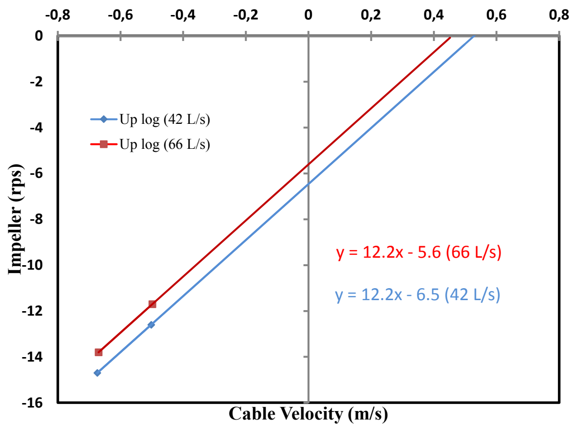

FIGURE 10: Well Pal-30D showing RPS of the spinner against cable velocity

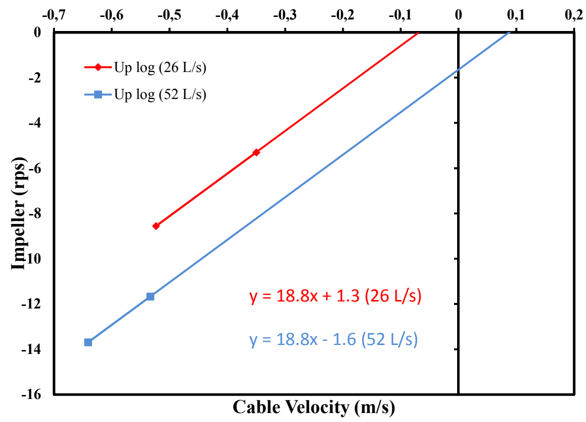

FIGURE 11: Well TW-4D showing RPS of the spinner against cable velocity

TABLE 1: Well MY-1D spinner data used in calculating the threshold velocity (Vt)

Up logs (Flow rate: 42 l/s)			Up logs (Flow rate: 77 l/s)		
Spinner (rps)	**Line speed (m/s)**	**Threshold velocity (m/s)**	**Spinner (rps)**	**Line speed (m/s)**	**Threshold velocity (m/s)**
-22.29	-0.52		-30.77	-0.51	
-24.13	-0.66	0.02	-32.61	-0.65	0.17
Average Vt : 0.09 m/s					

TABLE 2: Well Pal-30D spinner data used in calculating the threshold velocity (Vt)

Up logs (Flow rate: 42 l/s)			Up logs (Flow rate: 66 l/s)		
Spinner (rps)	**Line speed (m/s)**	**Threshold velocity (m/s)**	**Spinner (rps)**	**Line speed (m/s)**	**Threshold velocity (m/s)**
-12.6	-0.50		-11.7	-0.50	
-14.7	-0.67	0.08	-13.8	-0.67	0.08
Average Vt : 0.08 m/s					

TABLE 3: Well TW-4D spinner data used in calculating the threshold velocity (Vt)

Up logs (Flow rate: 26 l/s)			Up logs (Flow rate: 52 l/s)		
Spinner (rps)	**Line speed (m/s)**	**Threshold Velocity (m/s)**	**Spinner (rps)**	**Line speed (m/s)**	**Threshold velocity (m/s)**
-5.30 -8.56	-0.35 -0.52	0.07	-11.67 -13.69	-0.53 -0.64	0.09
Average Vt : 0.08 m/s					

3.1.2 Flow capacity calculation

Once Vt is obtained the average fluid velocity can be calculated using Equation 6. The volumetric flow of the injected water can then be calculated using Equation 7. In theory, the calculated volumetric flow should equal the injected water from the surface using rig pumps. These two values were seldom found to be equal because of the following factors:

- The efficiency of the rig pumps based on stroke per minute (SPM) is not 100%;
- Internal casing diameter of the wellbore may be corroded, deformed, etc., and therefore inexact;
- Internal diameter of the well in the open section is not known but is also variable due to cavities;
- The manual counting of the spm (stroke per minute) is affected by human error;
- The spinner data is not very accurate.

If stationary measurements in the well are available, it is best to use them when computing the total volumetric flow of the injected fluid. By using Equation 7, the volumetric flow is obtained. The mass flow can be calculated by multiplying the volumetric flow by the density of the fluid. Steps in calculating the feed zone contribution are:

- Use only the upward log data in getting the slope intercept for the feed point calculation. The upward logs are better measurements since they are going in the opposite direction of the fluid flow.
- Choose a sampling depth inside the casing where the diameter of the pipe is known to calculate the total flow rate coming into the wellbore (already done in the calibration).
- Take an average of 30 data points on each selected sampling depth, which should be the same for each flow rate in order to make the results of the calculations comparable.
- Choose a sampling depth interval above and below each feed point in order to measure the step or change in the flow rate.
- The flow rate after passing a feed point is determined by subtracting the total flow rate calculated below the feed point from the calculated flow rate above the feed point. Bear in mind whether it is inflow to or outflow from the well.
- The liner hanger restricts (or blocks) flow coming from the annulus outside the liner. The top few pipes of the liner are not slotted; most of (or all) flow will be inside the liner.
- Inside the slotted liner, however, the water will flow both inside the liner and also outside it. In the computation it is important to know the diameter of the well. This can be obtained by having a caliper log of the well.
- Caliper logging, however, is seldom done in geothermal wells in the Philippines. In such cases, the diameter is estimated either using the diameter of the drill bit used, or using what is called the effective radius of the well. The effective radius of the well can be determined by taking a sample flow calculation in the portion of the liner where no slots are found (meaning the radius is known) and take a sample flow calculation in the portion where the 1st few slots are found. Compare these two values and correlate to get the effective radius to be used in the calculation. Use the effective radius throughout the calculation down to the bottom of the well. It should be remembered that no cavities and washout zones are taken into account in these calculations.

It is important to study the spinner log carefully as well as the temperature log in order to identify the feed zones in each well and whether the flow is into or out of the well. This is used to decide the exact sampling depth to choose for calculating the contributions of the feed zones. Many of the anomalies are caused by changes in the diameter of the well; therefore, it is most important to analyse the temperature log with the spinner log to see which show feed zones. In Tables 4-6, the calculated mass flow for each feed zone located in the three analysed wells is tabulated as well as the change in spinner response at the feed zones and the fluid velocity.

A plot for well MY-1D with an injection rate of 14 l/s with each feed zone's contribution is shown in Figure 12 during the post acidizing completion test. The left part of the figure shows the pressure profile and the line speed during the survey. The pressure plot shows that the fluid in the well is in liquid phase (hydrostatic), denoting that the wellbore is full of water without any trapped gas. On the right part of the plot the temperature and spinner response are shown. Notice that in the 1st feed zone (depth 2000-2050 m) an increase of the spinner response is observed without any change in diameter. A slight change of the temperature is also evident, indicating an inflow of hot water. The flow was calculated at about 11.3 l/s of hot water coming into the wellbore (Figure 12 and Table 4). An increase of the spinner

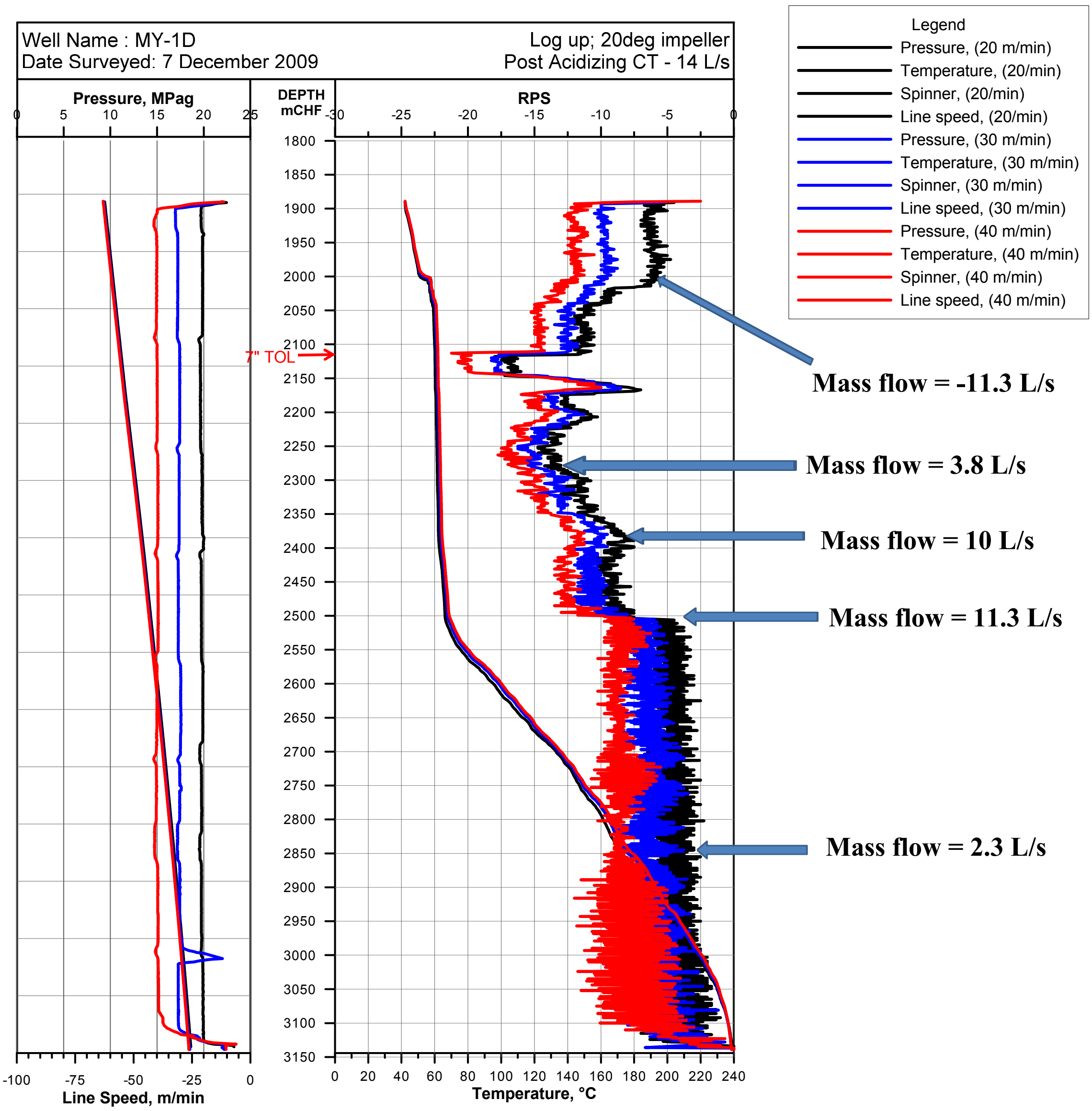

FIGURE 12: Well MY-1D PTS plot with corresponding calculated mass flow contribution for each identified feed zone while injecting 14 l/s

rotations around 2114 m is due to a change in diameter as the tool passes the top of the liner (TOL). A steady high response of the spinner is observed as it passes the solid part of the liner just above the first slots at 2150 m. The change in the spinner response after passing the slots is caused by a change in the diameter of the well as now some of the fluids flow outside the liner. This causes an irregular response by the spinner as it passes some cavities in the well outside the liner. At 2275-2375 m depth, a slight decrease in spinner response indicates an outflow zone. The calculated flow is 3.8 l/s (Figure 12 and Table 4). Another feed zone (depth 2350-2375 m) is evident as the spinner response decreases, indicating a water loss which is estimated at about 10 l/s (Figure 12 and Table 4). No change in temperature was observed at this depth in the temperature log. At 2500 m depth a decrease of spinner rotation was observed and identified as outflow of water in the feed zone (about 11 l/s). This is supported by a dramatic increase in temperature, as seen in Figure 12; so very little of the injected water flows beyond this depth. By this feed zone almost all of the injected water is lost into the reservoir. A minor change in the spinner log is observed at depth 2850-2900, indicating an outflow of about 2 l/s. The feed zone contributions are tabulated in Table 4. In all the flow calculations, it was assumed that the diameter of the well was close to the bit size. This is considered a good estimate as the sum of the calculated flows for the feed zone is 16 l/s, compared to 14 l/s injection.

A second plot of well MY-1D, with an injection rate of 77 l/s, is shown in Figure 13. Notice that the inflow, which is evident in the temperature log at 2000 m depth at a lower flow rate (Figure 12), is not

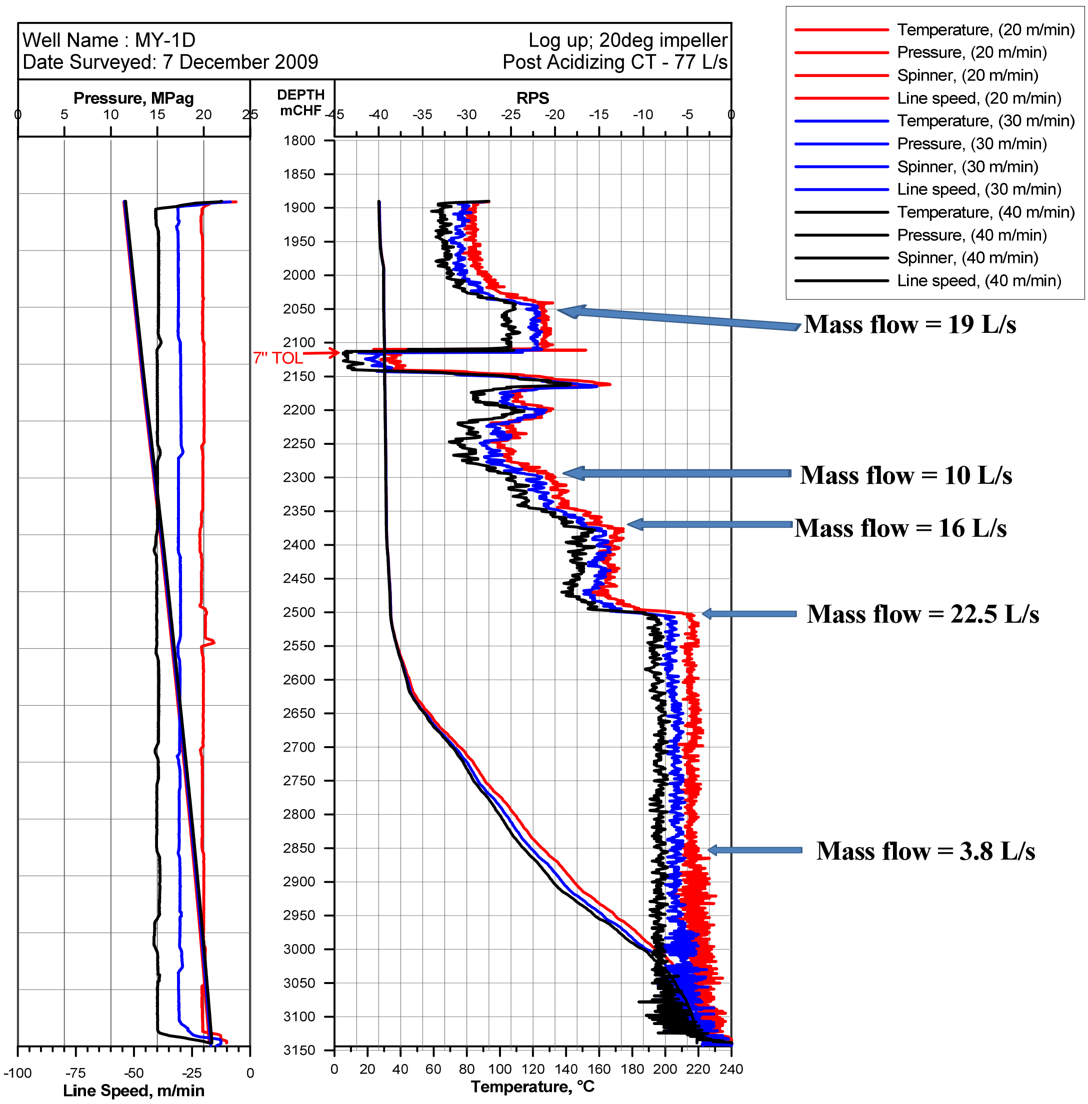

FIGURE 13: Well MY-1D PTS plot with corresponding calculated mass flow contribution for each identified feed zone while injecting 77 l/s

apparent on this graph. The inflow zone is suppressed by the pressure developed at a higher flow rate and a decrease in the spinner response at this depth was observed, indicating that it was now accepting water at a lower flow rate. The feed zones are more or less the same as seen on Figure 12 and accept the remaining water flow injected into the wellbore; the sum of the calculated flow into the feed zones is 71.3 l/s, compared to injection of 77 l/s (Figure 13 and Table 4). The calculation assumes the same well diameter as the drill bit size but the flow difference indicates an effective diameter a bit larger than 8.5".

The PTS plot for well Pal-30D during the post enhancement completion test with an injection flow rate of 42 l/s is shown in Figure 14. The left side of the figure shows the pressure profiles of the well and the different line speed during logging. The pressure log shows a liquid water column in the well. The figure on the right is the temperature profile and the spinner response. The temperature log does not show any inflow zones; as the temperature rises drastically below 3170 m, it is obvious that most if not all of the injected water is lost into feed zones at 3170 m and above. The spinner log shows a slight decrease of the spinner response (0.8 rps) at depth 1767 m (perforated section); the observed response indicates a flow loss of water through the perforation. This amount is calculated to be 3 l/s (Figure 14 and Table 5).

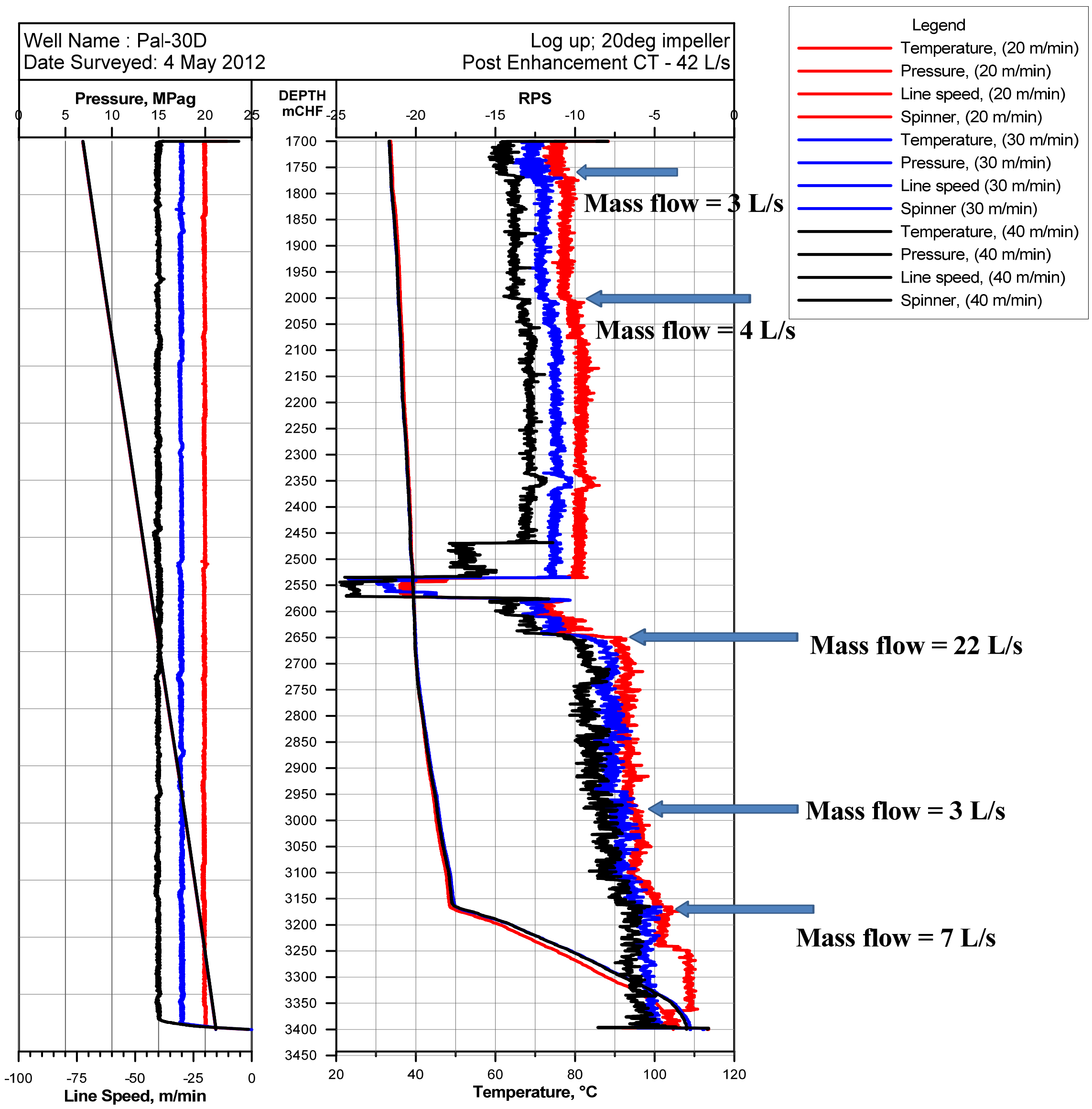

FIGURE 14: Well Pal-30D PTS plot with corresponding mass flow contribution for each identified feed zone while injecting 42 l/s

TABLE 4: Well MY-1D flow capacity calculation on each feed point during post acidizing well completion test conducted on 7 December 2009 while injecting 14 l/s and 77 l/s

Feed points (m)	**Change in spinner (rps)**		**Fluid velocity (m/s)**		**Flow rate (l/s)**	
	14 (l/s)	**77 (l/s)**	**14 (l/s)**	**77 (l/s)**	**14 (l/s)**	**77 (l/s)**
2000-2050	-5	8.3	0.76	1.97	-11.3	19
2275-2325	1.7	4.4	0.66	1.64	3.8	10
2350-2375	2.8	6.9	0.49	1.13	10	16
2500	5	9.9	0.18	0.39	11.3	22.5
2850-2900	1	1.9	0.11	0.25	2.3	3.8
				Total flow:	**16**	**71.3**
				Injection rate:	**14**	**77**

TABLE 5: Well Pal-30D flow capacity calculation on each feed point during a post enhancement well completion test conducted on 4 May 2012 while injecting 42 l/s

Feed points (m)	**Change in spinner (rps)**	**Fluid velocity (m/s)**	**Flow rate (l/s)**
1767.3-1781.3	0.8	0.94	3
2003.5-2081.6	1.1	0.85	4
2600-2675	5.5	0.42	23
2960-3000	1	0.34	3
3100-3175	2.6	0.13	7
		Total flow:	**40**
		Injection rate:	**42**

Another perforated section at depth 2003 m, wherein a decrease in the spinner response is 1.1 rps, indicates an outflow. The calculated outflow is about 4 l/s (Table 5 and Figure 14). The increase of the spinner response at depth 2470 m is caused by a change in diameter as the tool enters the liner (TOL). The first part of the liner consists of solid 8 ⅝" pipes to 2540 m where the 7″ solid liner starts, down to 2570 m. These changes in well diameter are the cause for the changes in the spinner response through this depth interval. In the slotted section of the 7 inch liner, a feed zone was observed at depth 2600 – 2675 m wherein a decrease of 5.5 rps of the spinner response was observed. Calculations of the response indicate an outflow of 21 l/s, so half of the injected water (42 l/s) is lost into this feed zone (Figure 14 and Table 5). A minor feed zone is seen at depth 2960-3000, observed as a little decrease of the spinner response (about 3 l/s). The deepest feed zone is observed at 3100-3175 m depth, which is manifested clearly in the temperature plot. All the remaining injected water is lost in this zone (7 l/s). The flow contribution is tabulated in Table 5. Summations show that the calculated values add up closely to the injection rate, indicating that a diameter estimation of 8.5" is reasonable.

A plot for well TW-4D during a post drilling completion test is shown Figure 15. The figure in the left shows the pressure profile of the well and the different line speed. The well is in liquid phase as indicated by the pressure profile. The plots on the right depict the temperature profile and the spinner response during the test. The temperature log shows that the injected water flows to the bottom of the well.

The spinner log starts at 1800 m depth. This is within the 10¾″ production casing (inner diameter (ID) ~9.5″) and the spinner response is 5 to 7.5 rotations per second for the three logging speeds. The spinner logs showed no changes when passing these sections of the casing since no change in diameter was observed. The main anomaly in the spinner logs, however, was seen at 1940 m, which is when the spinner tool entered the 8⅝" liner (ID ~7.5″) narrowing the flow channel. Note that there is a shift in depth (8⅝" TOL at depth 1926 m) as indicated in Figure 15, where the spinner response was observed at a depth of 1940 m. The bottom of the 8⅝" liner is at 2053 m depth. The 7″ liner starts at 2006 m and

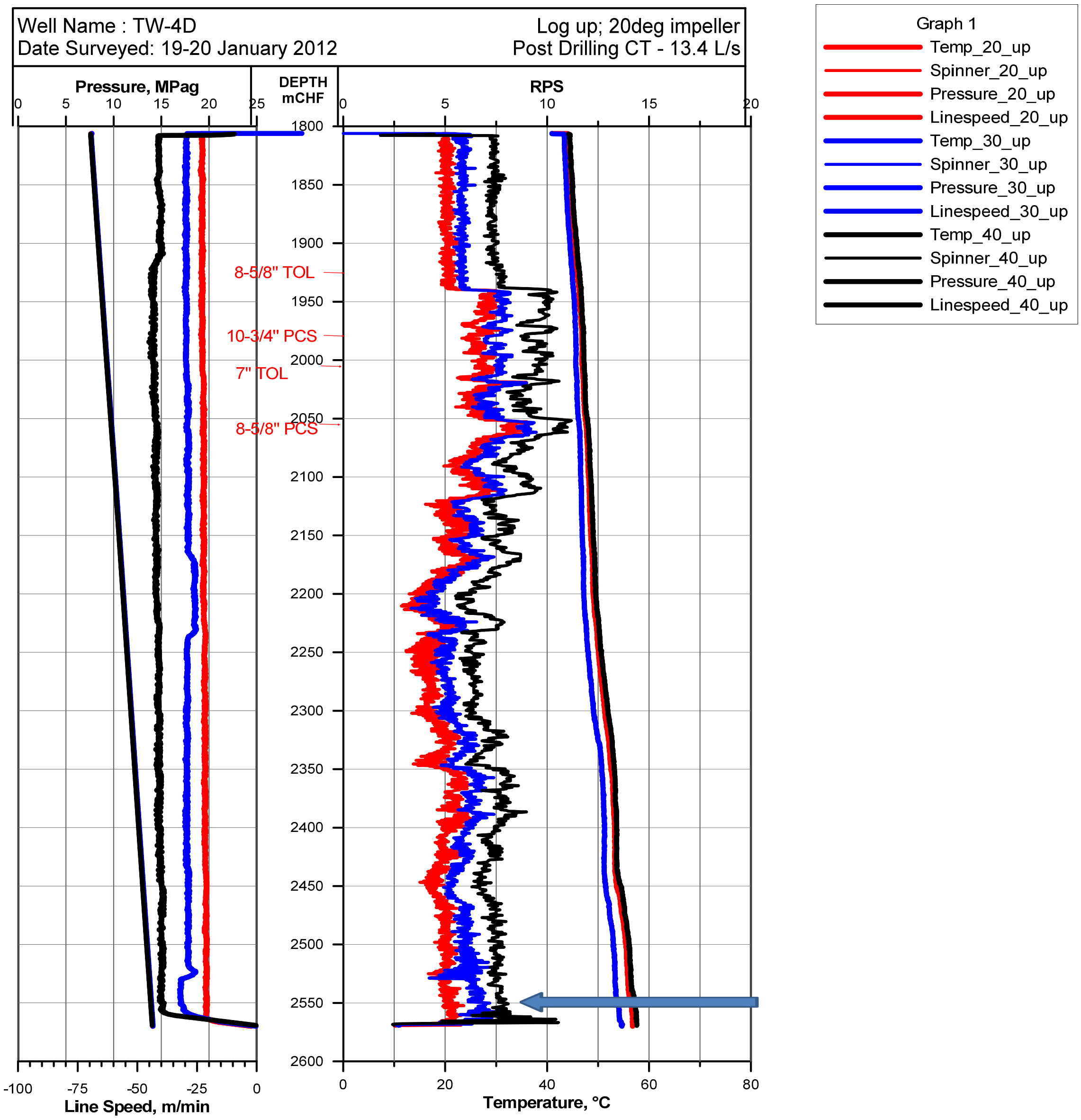

FIGURE 15: Well Pal-30D PTS plot with corresponding mass flow contribution for each identified feed zone while injecting 13.4 l/s

it overlaps the 8⅝" liner for about 50 m. No change was observed in the spinner log at 2005 m, indicating no flow restriction at the top of the 7″ liner or, in other words, the water flows free both inside the 7″ liner and in the annulus between the two liners. An increase in the spinner response was observed at depth 2053 m as it passed the bottom of the 8⅝" liner. There is no indication of inflow at this depth in the temperature logs, so the change must be explained by a change in the effective well diameter. After passing the bottom of the 8 ⅝"liner, an erratic response of the spinner was observed. This behaviour must be attributed to changing diameter along the wellbore caused by the cavities in the wellbore or a possible washout.

During drilling, the size of the wellbore is usually larger than the size of the drill bit. This can be explained: as the drill bit passes soft formations in the wellbore, the formations collapse creating cavities along the wellbore. This can be further explained in Figure 16, a well schematic showing the different sizes of the drill bit, the sizes of the casing and a caliper log depicting the cavities created in an actual drilling of wellbore. In Figure 15, the spinner response inside the production casing at 1800 to 1930 m is almost the same as the response from 2300 m to the bottom of the wellbore. It can only mean that fluid velocity Vf is the same in these two sections of the well. The inner diameter of the production casing is ~9.5″ and the drill bit size in the bottom section is 8.5”. Assuming no wash out in the bottom section, the bottom feed zone contributes at least 80% of the flow in the production casing. This is approximately 11 l/s of flow at the bottom. Hence, it is safe to assume that minor feed zones may be located in between, but it is not possible to determine the location from the spinner response or from the temperature log. The erratic change of the spinner after the TOL down to the bottom can be explained by changing diameters of the well, observed in Figure 16. It is not logical to have an inflow and outflow zone in between as it is not observed in the temperature profile. It is rather safe to assume that the wellbore has only one feed zone which is at the bottom where almost all the water is lost. The temperature profile and spinner response should always be taken into account when determining a feed zone. It is also clear that if a caliper survey is conducted, a more detailed analysis of the spinner log would be possible to explain these abnormalities and understand what is really happening inside the wellbore.

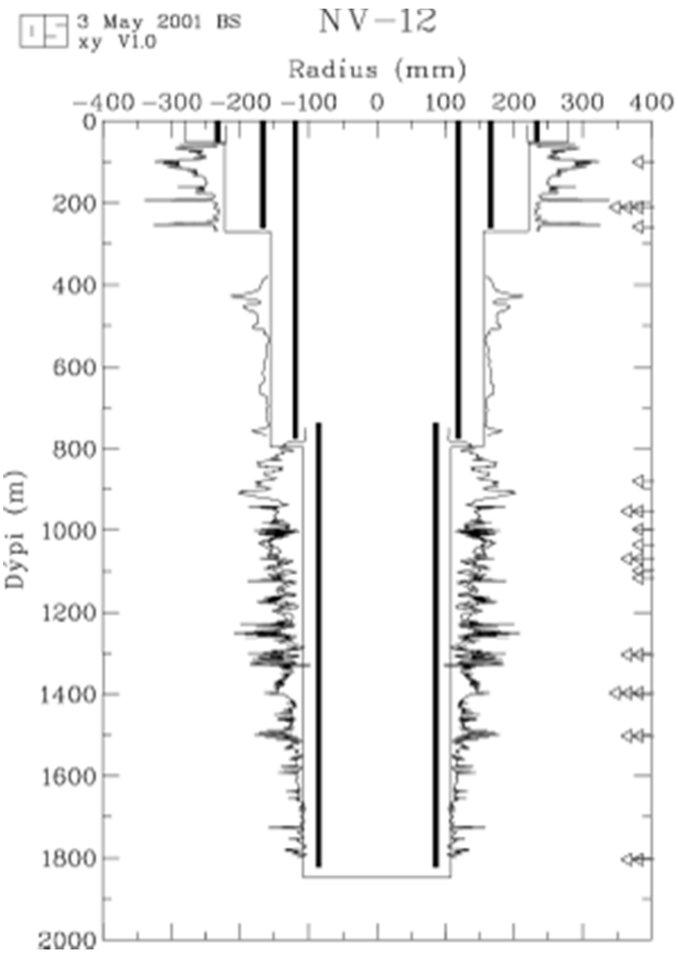

FIGURE 16: Schematic wellbore showing the drill bit sizes, casing sizes and caliper logs (ÍSOR, 2012)

3.2 Pressure transient analysis using WellTester, well TW-4D

3.2.1 The well test in well TW-4D and the WellTester software

Well TW-4D was subject to a well completion test on 30 January 2012, including a step test using four injection flow rates (Table 7) to evaluate whether the well had improved after enhancement operations were conducted. The injection rate was increased in the first 3 steps and decreased in the fourth and last step. The instrument was set at 1650 meters depth (Lejano et al., 2012).

As mentioned in Section 2.2, during a well test the pressure response in a well, due to a change in injection or production, is measured to infer a number of properties relating to the well and the surrounding reservoir. This is commonly done by setting up a mathematical model for the pressure transient response in the well and the reservoir, due to an instantaneous step change in injection (or production).

The data are prepared (see below) and inserted into WellTester which is used to do the analysis of the injection test. WellTester (WT) has been under development at Iceland GeoSurvey (ÍSOR) since 2006. This is GUI-based software which enables an analysis of the steps in a relatively easy manner and presents the results both graphically and in tables as well as a draft report. The available models in WellTester are homogenous or dual porosity, and the available boundaries in WT are constant pressure, infinite or closed boundary, which may be seen in Figure 17.

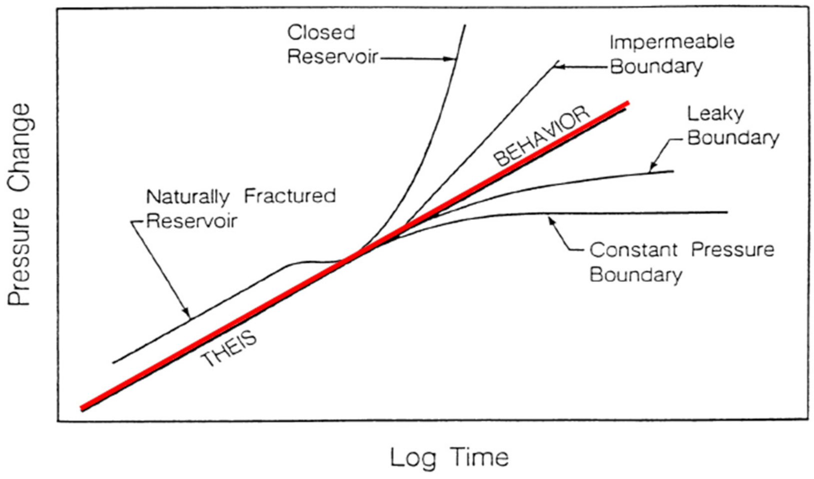

FIGURE 17: Boundary effects of the reservoir (Jónsson, 2012)

Additional options in the software are: skin or no skin and wellbore storage or no wellbore storage. After filling in these details of the model and boundaries, and the initial values of some of the parameters are selected "on screen", i.e. from the time-pressure graphs shown in WellTester, some guidance is given in the software as well as in a user guide on how to proceed (Júlíusson et al., 2008).

The mathematical model depends on characteristic values of the reservoir. By iterating and thereby improving the results, the simulation gradually gets close enough to the observed data for the characteristic properties of the reservoir to be deduced. This is an inverse modelling problem. A model is selected and parameters are modified according to the best knowledge of the user (an aid is included in WT). Then the parameters are calculated and compared to the prepared data, improving the model. Iteration, like many other problems in reservoir engineering, inherently yields somewhat ambiguous results. However, by carefully conducting the well test, considering and selecting the model of the reservoir and using computer aided analysis, the ambiguity in the results can be minimized. Moreover, an error estimate on the inferred parameters can be obtained through non-linear regression provided by the computer aided approach.

3.2.2 An injection well test in TW-4D and data processing

Before modelling the injection test results, the data obtained from the injection test (pressure versus time) needed to be prepared. The step test data were obtained from Scientific Drilling Inc., a 3rd party contractor that conducted the measurements. The data were first processed to accommodate the format needed in the WellTester software. Pressure which was in kilopascal was converted to bar. After reformatting the data, they were loaded into WellTester for modelling.

The measurements were not continuous for each step but were measured for about half an hour in the beginning and for about 30 to 60 minutes at the end of each step, except for the last step which was measured continuously. The pressure and injection were plotted in the WellTester program as shown in Figure 18. The change in flow rate at each step is shown in the figure as well. Each of the first three steps lasted for 3 to 5 hours but the last step (the pressure fall off step) lasted for 8 hours.

Information about the step test is given in Table 7 including the injection rate used in the well test, the change of injection and the pressure at the end of each step, as well as the injectivity index (II) for each step.

Often, the first resulting parameter which is considered in a well test is the injectivity index, II. This is the change in the injection rate against the change in pressure for each step (Table 7). A value for all 4 steps in well TW-4D can be found from a graph in Figure 19, where the pressure at the end of each step is shown as a function of the injection. The injectivity index 3.2 (l/s)/bar is the inverse of the slope of the best regression line through the four points in the figure.

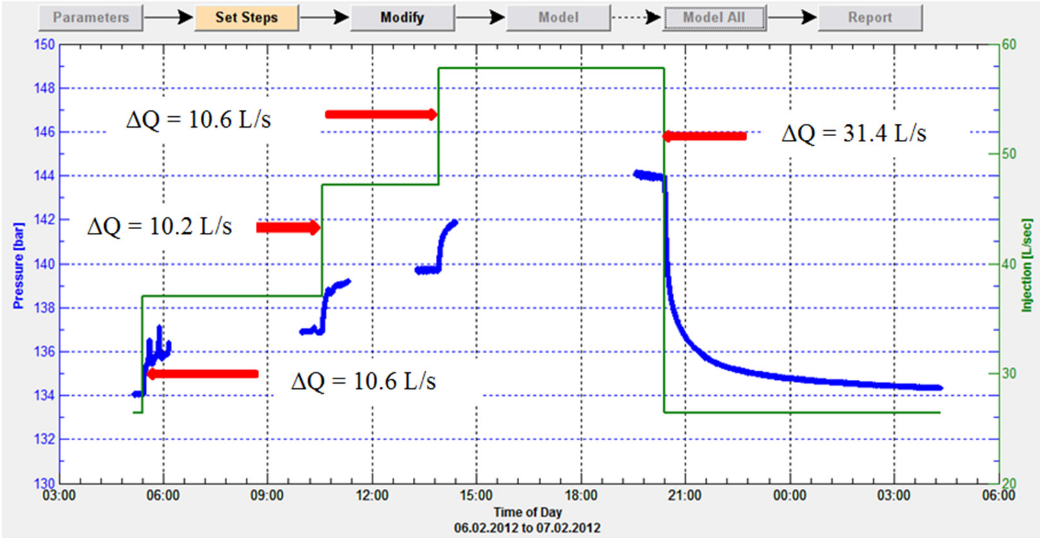

FIGURE 18: Well TW-4D – Pressure against time, with injection rate and change in flow rate during post enhancement step test, 30 January 2012, with a total of 4 steps (Table 7)

TABLE 7: Well TW-4D – Pressures at 1650 m depth at the end of each step for different flow rates during the injection test 30 January 2012 (Figure 18)

	Length of period (hr)	Injection (BPM)	Injection (l/s)	Changes of injection (l/s)	Pressure at the end of step (bar-g)	Injectivity index, II ((l/s)/bar)
Initial injection	0.3	9.9	-26	-	134	-
Step no. 1	5.2	14	-37	11	137	3.7
Step no. 2	3.3	17.8	-47	10	140	3.7
Step no. 3	6.5	21.8	-57	11	144	2.4
Step no. 4	7.9	9.9	-26	31	134	3.3

3.2.3 WellTester modelling and parameters

Good estimates of the initial parameters help in deducing information from the well test beyond the standard output. The initial parameter values used for this analysis are shown in Table 8.

When the initial parameters have been set, and the data have been plotted, the start of each step was identified (Figure 18). WellTester automatically looks for the beginning of the step, but an option to zoom in and modify the step is available. The beginning of each step was selected where the pressure started to increase in the first three steps and decrease in the fourth and last step. Each step was analysed individually. It is

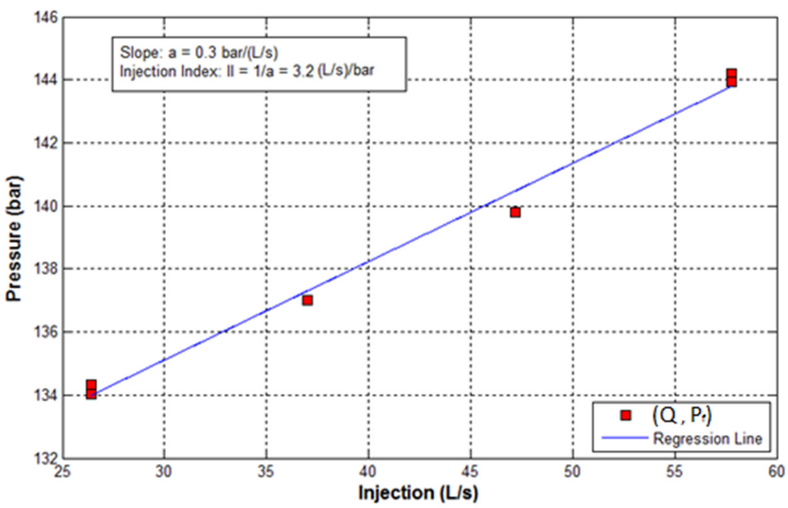

FIGURE 19: Well TW-4D – Pressure at the end of each step as a function of injection for determination of the injectivity index

TABLE 8: Initial parameters for well TW-4D used in WellTester

Initial parameters	Parameter value
Estimated reservoir temperature, (°C)	250
Estimated reservoir pressure (bar)	180
Wellbore radius (m)	0.16
Porosity (no unit)	0.10
Dynamic viscosity of reservoir fluid (Pa·s)	1.10×10^{-4}
Compressibility of reservoir fluid (Pa^{-1})	1.24×10^{-9}
Compressibility of rock matrix (Pa^{-1})	2.85×10^{-11}
Total compressibility (Pa^{-1})	1.49×10^{-10}

important to understand that WellTester works better on data with continuous measurements from the beginning to the end of the test, but here the steps were not measured continuously (Figure 18) as mentioned earlier, except for step 4. The model results of WellTester depend partly on how the data were modified. For a test with bad data (scattered noise data, missing data, etc.) the modeller has the option to modify the data based on his experience. This action could improve the results of the model but, on the other hand, it could contribute errors by adding wrong data points.

In order to learn how to use WellTester and test the data, an attempt was made to model the data with different models and parameters (options in WellTester). The boundary of the model selected is based on Figure 17, which shows the boundary effects of reservoirs. Possible models are: a) Homogeneous and b) Dual Porosity, with boundaries of the types: 1) Infinite and 2) Constant pressure; and all of them were tested. Each model was simulated for steps 1 to 4. The t-P diagram in Figure 18 shows that at the end of each step the pressure levelled out, i.e. a derivative plot *dP/dt* would tend to approach zero. This indicates a constant pressure boundary.

The best results from the tests (Table 9) were for a reservoir with "dual porosity", and a "constant pressure" boundary.

The selected model was used to simulate each step separately and then all four steps together. Using this model, a non-linear regression analysis was performed by WellTester to find the parameters that best fit the data.

TABLE 9: The model selected for the injection test in well TW-4D

Well testing model	Parameters
Reservoir	Dual porosity
Boundary	Constant pressure
Well	Constant skin
Well	Wellbore storage

3.2.4 Model results

The results from the interpretations of each step (steps 1-4) using the model presented in Table 9 are shown with three figures and a table for each step. Finally, a table with a summary of the results for all of the steps is presented, as well as the modelled results and the average of the results for the four steps.

The first figure (Figure 20) shows, on a linear scale, pressure in step 1 as a function of time for both the prepared data and the model results. The second figure shows the time-pressure diagram for step 1 on a log-lin scale (a logarithmic timescale in Figure 21a) and the pressure change as a function of time on a log-log scale (Figure 21b), together

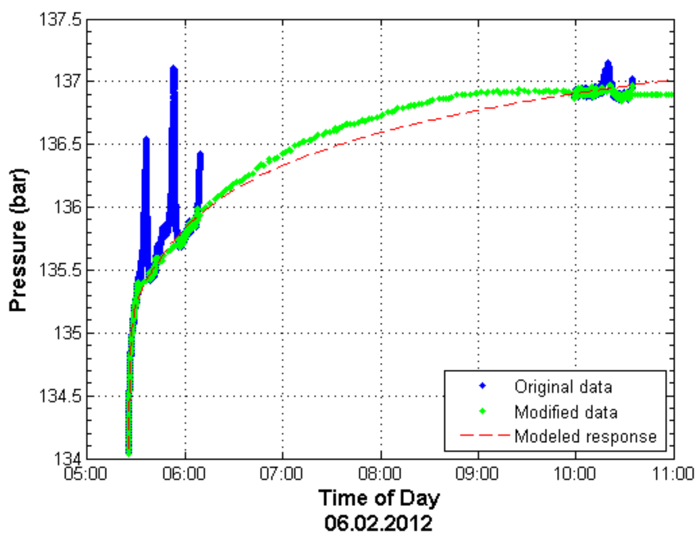

FIGURE 20: Well TW-4D, step 1, pressure vs. time, sampled data and model results

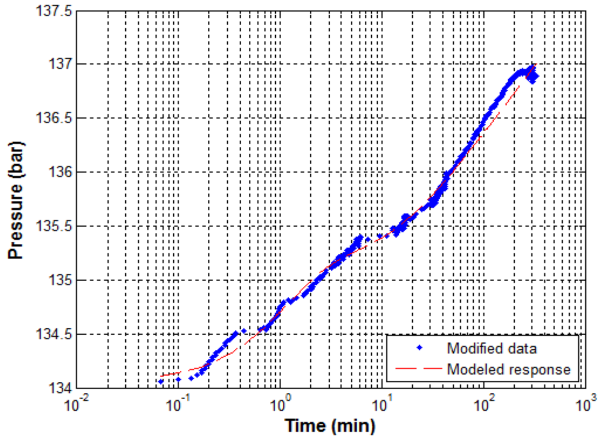

FIGURE 21: Well TW-4D, step 1; Pressure vs. time on a log-lin scale for sampled data and model results (left); Pressure change (above) and derivative of pressure (below) vs. time on a log-log scale for sampled data and model results (right)

with the derivative of the pressure response multiplied by the time passed since the beginning of the step. This derivative plot is commonly used to determine which type of model is most appropriate for the observed data. Dual porosity is represented in the hump on the derivative graph, i.e. decreasing derivative and then increasing again due to a "second flow" which increased the change in pressure. Constant pressure can be identified at the end of the step where it levelled out, and the derivative tended towards zero. The irregularities in the pressure at the beginning of the step are probably due to problems with the pumping rate, and these cause irregularities which a model cannot represent. Therefore, the data were prepared before modelling (visible in the figures) and the results should be considered less reliable than for step 4.

TABLE 10: Well TW-4D, step 1, results from non-linear regression parameter estimates

Parameter name	Parameter value	Cv (%)	Parameter unit
Transmissivity, T	2.0×10^{-8}	1.4	m3/(Pa·s)
Storativity, S	4.6×10^{-7}	7.1	m3/(Pa·m^2)
Skin factor, s	-2.1		-
Wellbore storage, C	1.0×10^{-5}	3.8	m^3/Pa
Injectivity Index, II	3.7		(l/s)/bar

The reservoir parameters relevant to the selected model for step 1 are shown in Table 10. The values shown for each parameter are the best estimates from the non-linear regression analysis of the measured data. The regression analysis gives information on the quality of the parameter estimates, represented by the upper and lower limits of a 95% confidence interval which are not shown here. On the other hand, the coefficient of variation, Cv, is given as a percentage in the table.

The results of steps 2, 3 and 4 are shown in a similar way, where Figures 22-23 and Table 11 show the results for step 2, Figures 24-25 and Table 12 show the results for step 3, and Figures 26-27 and Table 13 show the results for step 4.

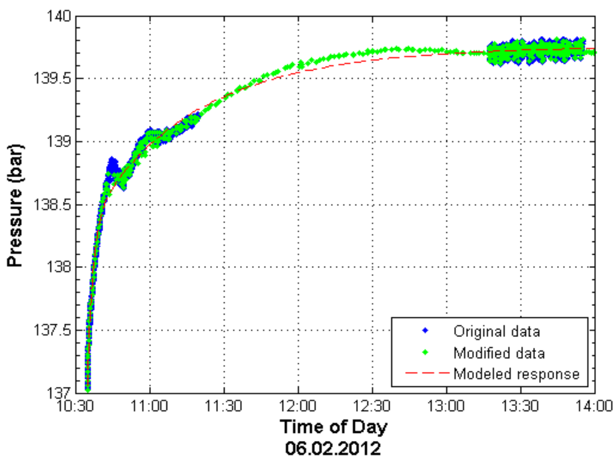

FIGURE 22: Well TW-4D, step 2, pressure vs. time, sampled data and model results

The values obtained for the transmissivity and the storativity can be used together with the given initial parameters to deduce an estimate of the reservoir's thickness and effective permeability. It should be emphasized that these estimates rely on parameters that are generally quite poorly known and should, therefore, be viewed more as orders of magnitude of the results from WellTester.

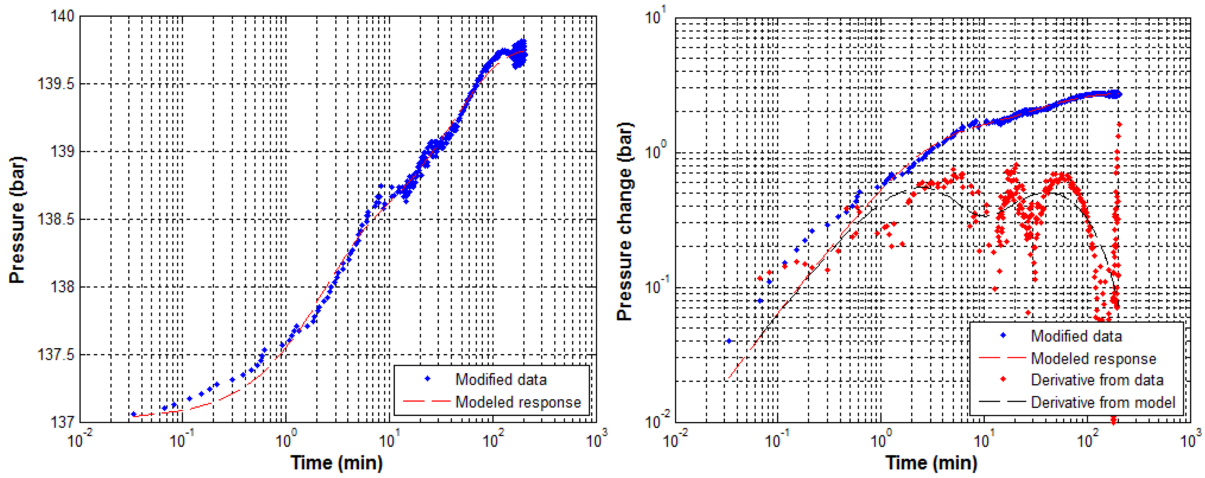

FIGURE 23: Well TW-4D, step 2; Pressure vs. time on a log-lin scale for sampled data and model results (left); and b) Pressure change (above) and derivative of pressure (below) vs. time on a log-log scale for sampled data and model results (right)

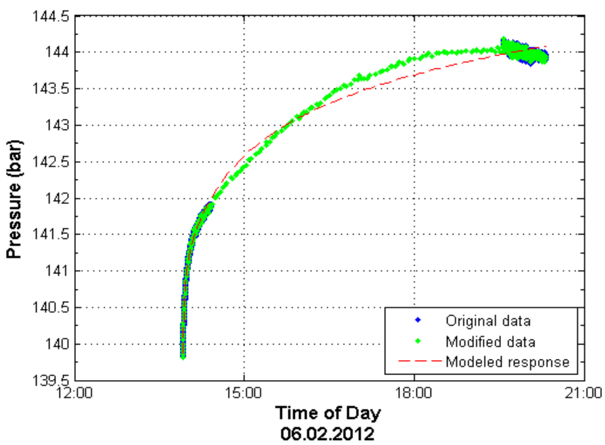

FIGURE 24: Well TW-4D, step 3, pressure vs. time, sampled data and model results

If the injection test consists of more than one step, the last part of the simulation may concentrate on all of the steps together, using the same model.

It may be noticed that the results for step 1 (Figures 20-21 and Table 10) and step 3 (Figures 24-25 and Table 12) are worse than for step 2 (Figures 22-23 and Tables 11) and step 4 (Figures 26-27 and Table 13). The reason, as mentioned earlier, is that the data jumps in the beginning of step 1 are caused by unexpected changes in the pumping rate while, in step 3, the location or depth of the measurements at the beginning and end of the step may not be the same.

Table 14 shows the results for "model all" and is similar to the previous tables for each step, but here WT simulates all of the steps simultaneously

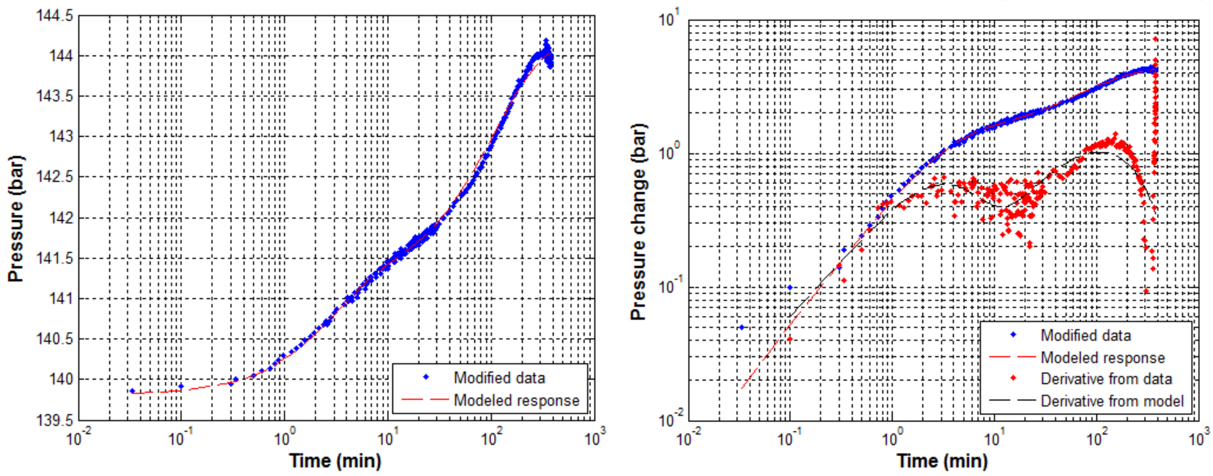

FIGURE 25: Well TW-4D, step 3; Pressure vs. time on a log-lin scale for sampled data and model results (left); and Pressure change (above) and derivative of pressure (below) vs. time on a log-log scale for sampled data and model results (right)

with the same parameters. Table 15 shows a summary of the results for each step, their average and the results from modelling all of the steps together. Note that the results of modelling all of the steps together are comparable to the results of the analysis with Sapphire (Lejano et al., 2012) from which the calculated injectivity index was 3.2 (l/s)/bar, permeability thickness 5.94 darcy-meter (Dm), and skin -3.4, whereas these were 3.3 (l/s)/bar, 5.4 Dm and -2.3, respectively, in WellTester.

TABLE 12: Well TW-4D, step 3, results from non-linear regression parameter estimates

Parameter name	Parameter value	Cv (%)	Parameter unit
Transmissivity, T	9.5×10^{-9}	1.4	$m^3/(Pa \cdot s)$
Storativity, S	3.6×10^{-8}	6.7	$m^3/(Pa \cdot m^2)$
Skin factor, s	-4.1		-
Wellbore storage, C	1.1×10^{-5}	4.4	m^3/Pa
Injectivity Index, II	2.5		(l/s)/bar

Although the coefficient of determination for "model all" in WellTester was relatively low, the results for the individual steps had much better coefficients of determination. For modelling all of the steps together, the results for step 4 were selected as the initial parameters in modelling, since the data were continuous and did not need to be modified, as may be seen in Figure 26. For the data in the present study, probably the results of step 4 should be considered the most reliable and representative for well TW-4D, since the other steps were not continuous and, therefore, the results are less reliable.

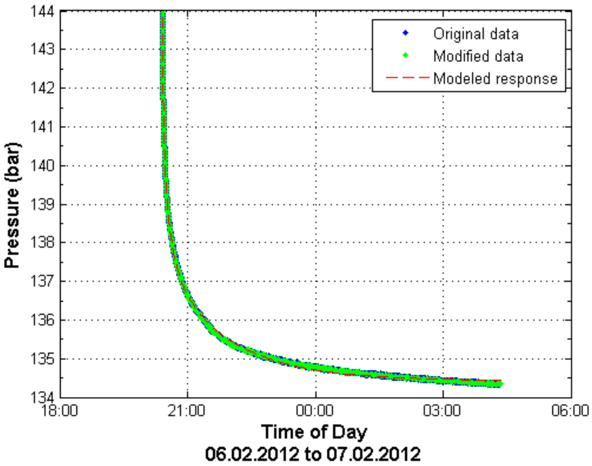

FIGURE 26: Well TW-4D, step 4, pressure vs. time, sampled data and model results

In Figure 28, step 4 was modelled using a dual porosity model with an infinite boundary but with no wellbore storage and no skin. Dual porosity was given emphasis, as the derivative plot of the data showed a hump or a cycle effect (up and down) which suggested a second source of the pressure change. The model fit the data after about 2-3 minutes, while in the earlier minutes the fit was not good. The plot shows that the well has skin and wellbore storage which are effective during the first minutes, and are included in the dual porosity model shown in Figure 27. By trying different models with different parameters, plots with good results could be found. With experience, it is easy to distinguish which model is the most suitable for the analysis of a step test.

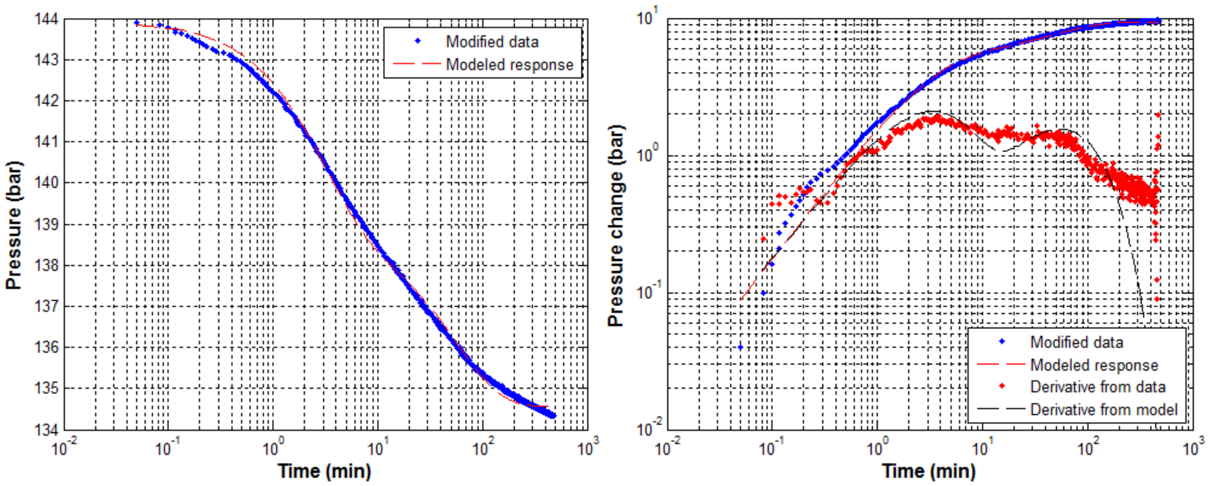

FIGURE 27: Well TW-4D, step 4; Pressure vs. time on a log-lin scale for sampled data and model results (left); Pressure change (above) and derivative of pressure (below) vs. time on a log-log scale for sampled data and model results (right)

TABLE 13: Well TW-4D, step 4, results from non-linear regression parameter estimates

Parameter name	Parameter value	Cv (%)	Parameter unit
Transmissivity, T	2.3×10^{-08}	0.5	$m^3/(Pa·s)$
Storativity, S	4.3×10^{-09}	5.1	$m^3/(Pa·m^2)$
Skin factor, s	-3.3		-
Wellbore storage, C	8.5×10^{-06}	0.8	m^3/Pa
Injectivity Index, II	3.3		(l/s)/bar

TABLE 14: TW-4D, all steps, results from non-linear regression parameter estimates

Parameter name	Parameter value	Cv (%)	Parameter unit
Transmissivity, T	4.9×10^{-8}	18.6	$m^3/(Pa·s)$
Storativity, S	1.8×10^{-9}	139	m^3/(Pa·m2)
Skin factor, s	-2.3		-
Wellbore storage, C	1.5×10^{-5}	24.7	m^3/Pa
Injectivity Index, II	3.3		(l/s)/bar

TABLE 15: TW-4D – Overview of WT-results from steps 1 to 4, average and all steps modelled together; the best results are from step 4, which had continuous measurements during the step

	Step 1	Step 2	Step 3	Step 4	Average	All steps together
Transmissivity, T	1.9×10^{-8}	1.1×10^{-8}	9.5×10^{-9}	2.3×10^{-8}	1.6×10^{-8}	4.9×10^{-8}
Storativity, S	4.6×10^{-7}	1.7×10^{-8}	3.6×10^{-8}	4.3×10^{-9}	1.3×10^{-7}	1.8×10^{-9}
Skin factor, s	-2.1	-4.5	-4.0	-3.3	-3.5	-2.3
Wellbore storage, C	1.0×10^{-5}	9.1×10^{-6}	1.1×10^{-5}	8.5×10^{-6}	9.9×10^{-6}	1.5×10^{-5}
Injectivity index, II	3.6	3.8	2.5	3.3	3.3	3.3
Permeability thickness, Dm	2.2	1.2	1.0	2.6	1.7	5.4

It is important that the injection test is complete and data measured continuously for 3 to 5 hours, and not with only a half hour in the beginning and the end of the step. Modifying the data by excluding some data points and adding points in the main data will never replace good, continuous measurements. When the test is not measured as a continuous sequence at the same depth in the well, the change in pressure can be either higher or lower than the real value which directly affects the injectivity index, as well as other results in the model.

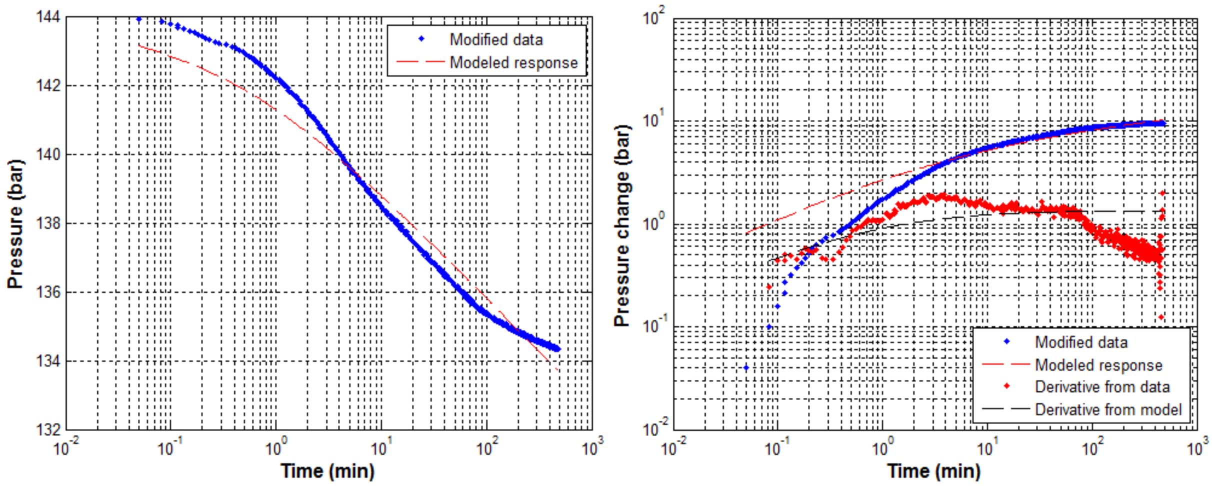

FIGURE 28: Well TW-4D, dual porosity without wellbore storage, step 4; Pressure vs. time on a log-lin scale for sampled data and modelled results (left); Pressure change (above) and derivative of pressure (below) vs. time on log-log scale for sampled data and model results (right)

4. CONCLUSIONS

A Pressure-Temperature-Spinner (PTS) survey is routinely conducted in all geothermal wells operated by Energy Development Corporation in the Philippines. The PTS-measurements are generally used to characterize the well and the reservoir. Injectivity tests and flowing surveys are usually conducted with the PTS tool. The PTS measurements can be analysed to get information about the reservoir and the contribution of a feed zone to the total flow of a well. The pressure and temperature data are more stable than the spinner data, which can be noisy and hard to work with.

Spinner data are useful in calculating the feed zone contribution of a geothermal well, and quantifying how much it contributes to the total flow. Spinner data are not simple to use, and it is rather complicated to determine the threshold velocity of the propeller of the spinner. Reliable information about the wellbore, e.g. circulation losses during drilling, as well as information about casings, their dimensions and depth, which can affect the spinner response, as well as temperature logs are necessary to be able to interpret the spinner measurements. The spinner data are very sensitive to changes in the diameter of the well and the type of fluid (viscosity) inside the wellbore, and these need to be considered carefully during the interpretation. To counter check the calibration with a stationary log is useful.

Pressure transient analysis results from an injection test give information on the storativity, permeability, and thickness of the reservoir as well as the injectivity index and skin of the wellbore. In this study, WellTester software from ÍSOR was used to model pressure response during a well test, changing the injection in steps in well TW-4D. The results were similar to the previous model results from Sapphire (Lejano, et al., 2012). The results from WellTester are clearly useful and comparable to results from other widely used software. It is free software from ÍSOR and is still under development. WellTester, as for probably all modelling software, works best if the injection test is complete and continuous. Modifying the data is not a good practice because it may improve the outcome but may, on the other hand, give fictitious results.

To improve results using spinner data, a caliper log is necessary to analyse feed zone contributions. This will help explain the irregular behaviour of the spinner response inside the wellbore. A change in diameter of the wellbore reflects immediately on the spinner response. Information about the diameter changes, such as cavities, eliminates confusion on whether a feed zone is present or just a change in diameter is responsible.

For pressure transient analysis, continuous recordings at a selected depth in a step test are crucial to minimizing external errors. Therefore, the results of step 4 should probably be selected as respresentative of well TW-4D, since the other steps were not continuous and the results are much less reliable. If the completion test is measured as in the step test which was analysed here for well TW-4D, it is very important to ensure the exact location of the tool from the start of the test to the end in order to avoid errors in pressure changes. This will provide more reliable data during modelling.

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