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International Journal of Rock Mechanics & Mining Sciences 42 (2005) 1082–1087
International Journal of Rock Mechanics and Mining Sciences
www.elsevier.com/locate/ijrmms

Technical note

Estimation of hydraulic parameters after stimulation experiments in the geothermal reservoir Groß Schönebeck 3/90 (North-German Basin)

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Accepted 3 May 2005
Available online 5 July 2005

1. Introduction

The well Groß Schönebeck 3/90 lying about 50 km northeast of Berlin in the North-German Basin was reopened in 1999 and deepened in 2000 to 4294 m depth for the purpose of developing appropriate stimulation methods to increase permeability of deep aquifers.

The well goes through the typical sequence of various geological formations known in the North-German Basin. A series of 2370 m of sediments from Cretaceous over Jurassic to Triassic is underlied by 1511 m of Zechstein-evaporites (Fig. 1). The 400 m open-hole section at the bottom of the well comprises Rotliegend siltstones, sandstones, conglomerates and volcanic rocks. Bottom hole temperature reaches approximately 150 °C [1,2] (Fig. 1).

According to experience a production rate of 50 m^3/h is a necessary condition for economic and sustainable generation of geothermal electricity. At most locations this rate cannot be accomplished in depths over 3000 m due to the low initial permeabilities of the reservoir rocks. For that reason, hydraulic stimulation treatments are required. Consequently, stimulation as well as production tests with the purpose of influencing and determining the hydraulic properties of the reservoir were performed in the research well.

Two intervals of the Rotliegend sandstones were hydraulically stimulated in January 2002 using a high viscosity fluid with proppants. In order to study the hydraulic parameters in more detail a long-term hydraulic test was carried out in summer 2002 [3]. This moderate pumping test suffers from the problem of multiple flow rates (compare Fig. 3). Consequently, a desuperposition from the varying flow rate q and the corresponding wellbore pressure p_w is necessary for an optimal evaluation.

2. Sandstone stimulation and moderate pumping test

The stimulation concept followed the traditional oil industry procedures. First, the test interval was isolated by filling the bottom of the well with sand and sealing the top with a mechanical packer. High viscosity fluid (polymers) with proppant was used for the well stimulation. Since stimulation operations are accomplished in the open hole section and under high temperatures, a less aggressive fracturing design was applied to avoid a by-pass of the packer. Three weeks after the stimulation the effectiveness of the treatment was assessed with a flowmeter log and a casing lift test (CLT) over the total open-hole section. Production rates of 25 m^3/h were obtained. However, the observed flow rates were not sufficient for economic power production [3]. Tischner et al. [4] analyzed the CLT and argued that similar pressure matches for a radial model and a fracture model can be created due to the short duration

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1365-1609/$ - see front matter
doi:10.1016/j.ijrmms.2005.05.009

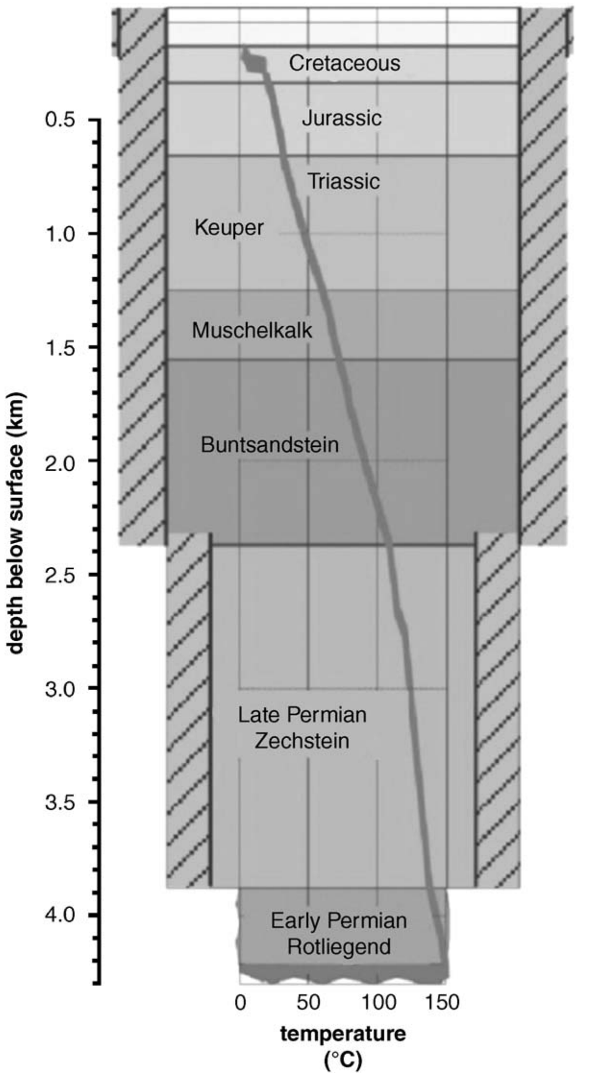

Fig. 1. Lithology- and temperature-profile of the well Groß Schönebeck 3/90.

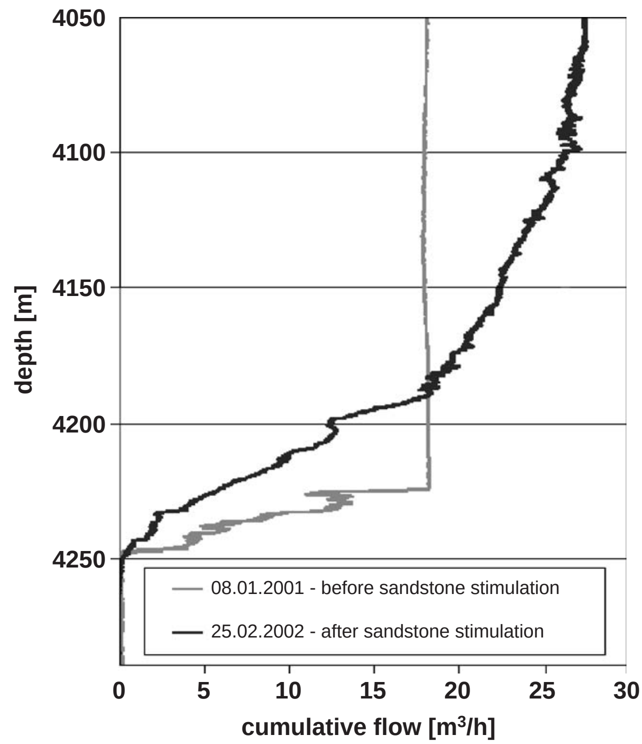

Fig. 2. Cumulative flow measured with a flowmeter during short term lift tests to obtain the inflow zones.

of the test. For the fracture model they calculated a rough estimate of the fracture half length x_f of 105 m, but with high uncertainty and low hydraulic conductivity [4]. (For the calculation of x_f Tischner et al. [4] used a total compressibility c_t of $5 \times 10^{-9}\,\mathrm{Pa}^{-1}$ and a reservoir thickness h of 25 m, taken from the initial flow log (Fig. 2). Other values are specified below.) Therefore, it can be assumed that the effect of the stimulation treatment was mainly limited to the vicinity of the borehole and hence can be interpreted as a skin reduction.

Fig. 2 displays a comparison of the flow log before and after the treatments. Before well stimulation no response in the Rotliegend sections above 4225 m could be seen, only at the transition zone between the conglomerates and the volcanic rock an inflow over 25 m is visible. After stimulation the flow log shows a response to a depth up to 4100 m indicating that the Rotliegend sandstones could be activated.

In order to estimate the hydraulic parameters in more detail, a long-term pumping test was performed in summer 2002 [3]. The aim of the moderate pumping tests in Groß Schönebeck was the production of formation fluid over a long period of time with a constant flow rate. A small flow rate was chosen, so that non-Darcy flow does not apply. The long-term production of fluid allows a greater radius of investigation to estimate the extent of the reservoir. Hence, the skin properties as well as the long-term radial behavior of the reservoir can be assessed.

A hydraulic down-hole pump was installed in 330 m depth (the water level is at 250 m in equilibrium). The flow rate was set to approximately 0.5–1.0 m^3/h over a period of 37 days. A total amount of 580 m^3 of formation fluids was produced. During the test a slight decrease in the flow rate could be observed. After 10 days the draw-down reached a constant level, but steady state conditions were not reached until the end of the test (Fig. 3).

The build-up observation was split into two parts. First a packer was set in the borehole and the pressure behavior was measured under shut-in conditions. Unfortunately, the packer leaked and optimum shut-in conditions could not be maintained over the whole measurement period. Subsequently the measurements were continued with an open hole pressure monitoring [3].

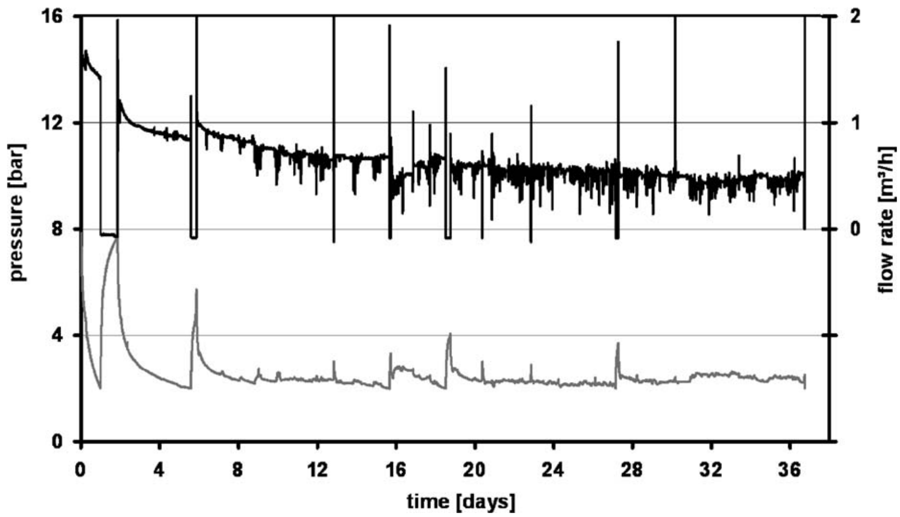

Fig. 3. Pressure and flow rate of the draw-down of the moderate pumping test carried out in Groß Schönebeck 3/90 during August/September 2002.

3. Derivative plots

For model recognition double logarithmic derivative plots [5] (Fig. 4a and b) were generated from both the draw-down data and the build-up data of the moderate pumping test performed in the Groß Schönebeck well. The data of the draw-down plot (Fig. 4a) were filtered with a low-pass Butterworth filter to suppress the noise of the data. Nevertheless, the continuous derivatives had to be omitted at logarithmic times later than 4.9 due to the instabilities of the pressure measurements. Instead, linear regressions were calculated for these intervals and the correspondent derivatives were determined. At early stages the results in both the pressure and its derivative show the borehole storage effect, which is characterized by a slope of 1 in the log–log plot [5]. At late times the derivative converges to a nearly horizontal line, indicating a pseudo radial flow system. No clear indication for fractures, which should lead to a $\frac{1}{2}$ slope (for linear formation flow) or $\frac{1}{4}$ slope (for bilinear flow) [6] in the log–log plot, is visible in the data. The same holds for the build-up plot. The Agarwal effective time [5] was applied to obtain an equivalent derivative plot. Pressure and its derivative show a typical pseudo radial late time behavior of the reservoir with a constant derivative (Fig. 4b). Early times were omitted due to the leakage of the packer (compare Fig. 5). However, the monitoring of the pressure build-up is sufficiently long enough for the evaluation of it with a radial flow approach to obtain the reservoir transmissibility. Furthermore, there is no indication of a boundary of the reservoir which would lead to a pressure increase at the end of the test. A brief introduction to the radial flow approach will be given in the next chapter.

4. Transient pressure behavior for radial flow

The superposition of the line source solution [7] of the diffusivity equation for multiple flow rates q_j combined with the logarithm approximation for the exponential integral [5] leads to the following equation for the evaluation of pumping tests:

$$p_{\mathrm{w}}(t_n) = p_{\mathrm{i}} - \underbrace{\frac{\mu}{4\pi\pi k}}_{b} \bullet \underbrace{\sum_{j=1}^{n} \left[\Delta q_j \ \ln\left(t_n - t_{j-1}\right)\right]}_{x} + \underbrace{\frac{\mu}{4\pi\pi k} q_n \left[\ln\left(\frac{4k}{\gamma \phi \mu c_{\mathrm{t}} r_{\mathrm{w}}^2}\right) + 2S\right]}_{a} \tag{1a}$$

$$p_{\mathrm{w}}(t_n) = p_{\mathrm{i}} - b \quad \bullet \quad x \quad + \quad a \tag{1b}$$

where p_{w} is the wellbore pressure, p_{i} the initial pressure, μ the viscosity, k the reservoir permeability, h the reservoir thickness, t the time, γ the Euler's constant, ϕ the porosity, c_{t} the total compressibility, r_{w} is the borehole radius, and S the skin (explained in more detail below).

If the pressure data $p_{\mathrm{w}}(t_n)$ are expressed with a new basis $\Sigma\Delta q_j \ln(t_n - t_{j-1})$ (henceforth called "modified flow rate") which implies the variation of the flow rate, a desuperposition of pressure and flow rate can be performed. This method is a general form of the well-known Horner Method (HM) [8] and it is almost identical with the Multirate-Superposition-Plot-Technique (MSPT) which is described by Earlougher [9] and by Horne [5]. In contrast to the HM, the MSPT enables the determination of transmissibility from every flow rate step of a test if the steps are sufficiently long enough. The different steps are represented by straight lines in the Multirate-Superposition-Plot (MSP). Furthermore,

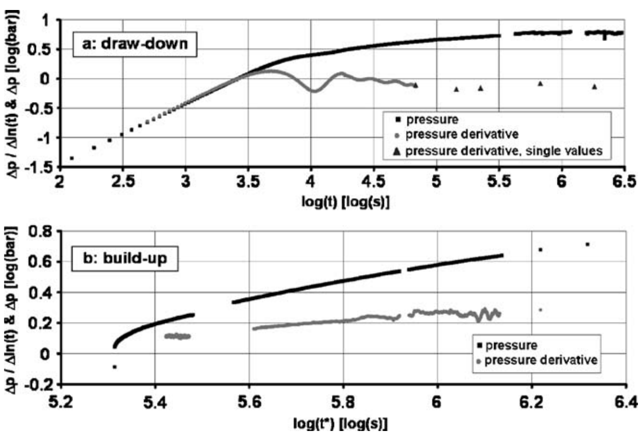

Fig. 4. (a,b)Derivative plots of the draw-down and the build-up data of the moderate pumping test; (t^* stands for the Agarwal effective-time).

it is not necessary to measure the build-up as long as the influence of flow rate variation becomes negligible.

The slope b (Eq. 1b) of the straight line in the MSP can be used to compute the transmissibility

$$T = \frac{\mu}{4\pi b}. \tag{2}$$

The skin S can be determined from build-up data (when the flow rate is zero) with following equation:

$$S = \frac{p_{\mathrm{ws}} - p_{\mathrm{w}}^{\Delta t}}{2bq_{n-1}} - \frac{1}{2}\ln\left(\frac{4k\,\Delta t}{\gamma\phi\mu c_t r_{\mathrm{w}}^2}\right). \tag{3}$$

For this formula to be valid it is essential that the last flow before shut-in is dominant in the reservoir. Additionally, the pressure before shut-in (p_{ws}) and at time Δt after shut-in ($p_{\mathrm{w}}^{\Delta t}$) are needed.

The skin defines a zone of reduced or enhanced permeability. The permeability reduction is caused by particles of drilling mud and/or physio-chemical fluid-rock interaction in the close vicinity of the borehole [5]. Such borehole damage can cause a considerable effect on the well productivity. Hence, stimulation methods like fracturing or acidizing are used frequently to reduce the skin. A positive skin means that the permeability is reduced in the close vicinity of the borehole while a negative skin stands for an improved permeability in the near wellbore region.

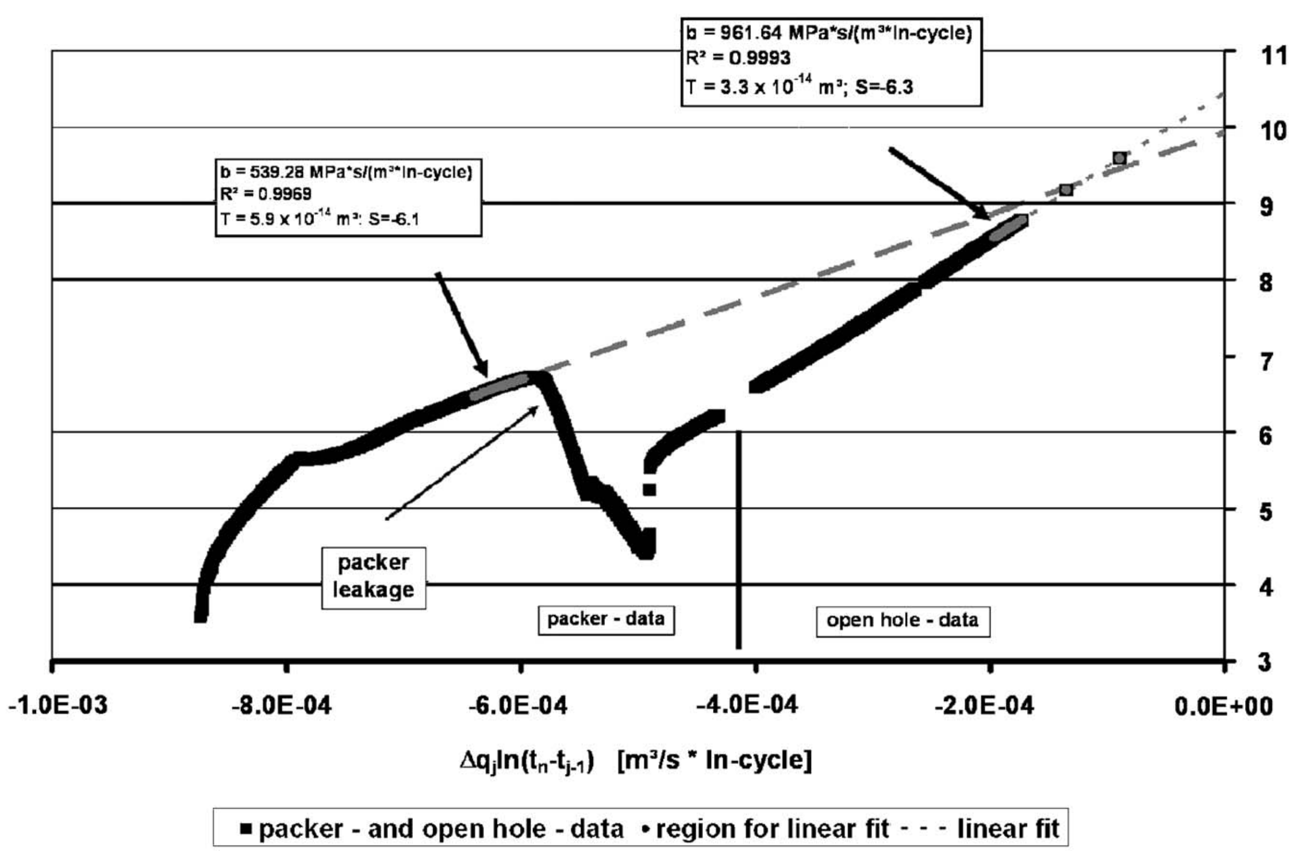

Fig. 5. Build-up data of the moderate pumping test evaluated with the MSPT.

5. Reservoir characterization

The packer data and the level data of the moderate pumping test were evaluated separately with the MSPT. The black line in Fig. 5 shows the pressure data; gray lines show the data intervals that were used for linear regression. The gray sketched lines represent the linear regression itself. The determined slopes, intercepts and linear regression accuracies are displayed in the figure.

For the following calculations the fluid viscosity was set to 4×10^{-4} Pa s, the total compressibility c_t to $1.1\times10^{-9}\,\mathrm{Pa}^{-1}$, the wellbore radius r_w to 0.075 m, the reservoir thickness h of 100 m was taken from the flow log measured after the sandstone stimulation (Fig. 2) and the porosity 0.05 was taken from core measurements [10].

Transmissibility of the productive formations was estimated from pressure build-up during the shut-in time to $5.9\times10^{-14}\,\mathrm{m}^3$ from the packer data and to $3.3\times10^{-14}\,\mathrm{m}^3$ from the level data. The skin was estimated to be −6. This obvious negative skin supports the interpretation of a limited stimulation treatment and reflects the good connection between the porous reservoir and the well due to the fractures close to the borehole. Since optimum shut-in conditions could not be maintained during the build-up the pressure signal is superposed by the borehole storage effect. Due to this fact the skin might be regarded as a trend but does not necessarily represent the actual conditions.

To confirm the radial flow approach a maximum radius of investigation was calculated to $R = 195$ m according to Lee [11] (assuming matrix permeability of $3.0\times10^{-16}\,\mathrm{m}^2$ and a total compressibility c_t of $5\times10^{-9}\,\mathrm{Pa}^{-1}$, other values are specified above). The radius of investigation is obviously larger than the created fracture with fracture half-length of 105 m [4], which is another proof for the radial flow approach.

Due to the long test duration, the build-up measurements of 107 days and the use of the MSPT the transmissibility value of $3.3\times10^{-14}\,\mathrm{m}^3$ represents the most reliable estimation of the reservoir transmissibility for the Rotliegend in the well Groß Schönebeck 3/90.

6. Comparison with the results of an earlier test

It is of general interest to understand the extent to which the reservoir parameters of the reservoir rocks of the well Schönebeck 3/90 have changed due to the stimulation experiments. Therefore, the results are compared to a nitrogen lift test, which was performed in 2001 as a primary test.

The transmissibility was determined with the HM from build-up data to $2.0\times10^{-14}\,\mathrm{m}^3$ [12]. A direct comparison with the current result of $3.3\times10^{-14}\,\mathrm{m}^3$ is not possible, because the lift test conditions were too different due to the short time of investigation. With short tests like the nitrogen lift test the calculated transmissibilities are too high in low permeable reservoirs, because no steady-state conditions can be reached in those short-term tests. Therefore, the value of $3.3\times10^{-14}\,\mathrm{m}^3$ already shows a clear improvement of the reservoir transmissibility due to the reservoir stimulation. The skin was determined to −0.1 in this nitrogen lift test [12]. The change of the skin to approximately −6 indicates an enhancement of the connection between the well and the reservoir.

7. Conclusions

Development of a technology to stimulate deep geothermal reservoirs in sedimentary basins is the purpose of installing the down-hole geothermal laboratory in the former gas exploration well in Groß Schönebeck. A moderate pumping test was performed in this well after stimulation treatments to investigate the long-term behavior of the reservoir. Diagnostic plots showed a clear indication of a late time pseudo radial behavior in this test. Therefore the MSPT could be successful applied for the evaluation of the moderate pumping test and the transmissibility of the Rotliegend in the well Groß Schönebeck 3/90 was determined to $3.3\times10^{-14}\,\mathrm{m}^3$. This value represents the most reliable estimation of this reservoir. The clear pseudo radial flow stage can be interpreted as a limited fracture generation, which merely led to a decrease in skin and hence is limited to the borehole vicinity.

Compared to the initial condition, the flow rate could be increased substantially. Nevertheless, the flow rate after the treatment is still to low for a profitable generation of geothermal electricity; additional stimulation experiments are necessary.

Acknowledgements

This multidisciplinary project is a joint venture of research institutes (GFZ Potsdam, BGR Hannover, GGA Hannover), Universities (TU Berlin, RU Bochum) and industry partners (GTN Neubrandenburg, BWG Neubrandenburg, MeSy Bochum). It is funded by BMWI, BMBF, BMU, MWI Brandenburg and MWFK Brandenburg.

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