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Well Test Analysis After Massive Waterfrac Treatments in a Sedimentary Geothermal Reservoir

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ABSTRACT

A series of stimulation experiments were carried out in a geothermal research well in the northeastern part of Germany with the aim of geothermal technology development. In a first attempt open hole hydraulic proppant fracturing treatments were conducted in two pre-selected sedimentary reservoir zones. They proved to be on the one hand technically demanding and on the other hand due to a suboptimal design less successful than expected. Nevertheless, the main inflow zones could be clearly identified. In a second step the concept of zonal selection and proppant application was abandoned and massive waterfrac treatments including small injection tests in the beginning were applied over the entire open hole interval of the well (3874-4294m). Due to bore instabilities the treatments had to be temporarily suspended. The problems were mastered by installing a pre-perforated liner. The wellbore was stabilized, the hydraulic accessibility to the pay zones as well as safer treatment conditions guaranteed for the continuation of the waterfrac experiments.

On this basis, changes of hydraulic parameters due to the various stimulations will be analysed and discussed. Evidence of the creation and properties of vertical fractures are retrieved from pressure response analyses. Data from production and flow back tests as well as from borehole images (BHTV and FMI) are being used for the analyses.

Therefore, the stimulation effect in terms of a productivity increase can be determined for the described concepts and improvements can be recommended for similar field experiments.

1. INTRODUCTION

Sustainable and environmentally friendly energy can be generated from the conversion of Earth's heat (from formation fluids) into electricity. The precondition for an economic generation of geothermal electricity are sufficiently high temperatures and flow rates of about 50 m^3h^{-1} and 150 °C. The required temperature for this purpose can be found in the North German Basin in 4000 m to 5000 m. However, in this depth permeability of the rocks is generally insufficient for the necessary flow rates.

The site Groß Schönebeck is promising. The well makes deep hydrothermal aquifers accessible with formation fluids of 150 °C and porosities of up to 10 % (Huenges & Hurter, 2002). Experiments in this in situ geothermal laboratory should lead to a reliable technology for sufficient production of deep fluids in such reservoirs.

2. GEOLOGY

The former gas well Groß Schönebeck 3/90 drilled in 1990 was re-opened and deepened to 4294 m at the end of the year 2000 to establish an in situ laboratory for experiments. The drill site is located northeast of Berlin. The well encounters the typical sequence of various geological formations, known in the North German Basin. A series of 2370 m of Quaternary to Triassic sediments is under lied by 1492 m of the Zechstein salinar and the following section of this well, which was foreseen for testing, comprises 400 m of Rotliegend formation (siltstones, sandstones, conglomerates and 60 m of underlying volcanic rocks) up to the final depth of 4294 m (Huenges et al., 2002).

3. STIMULATION EXPERIMENTS

Technologies have to be developed to enhance the existing flow. This can be summarized by the term *hydraulic fracturing*. During stimulation experiments fluids under high pressure penetrate into the rock and generate or extent fractures. These procedures are well known in hydrocarbon industry as well as in the Hot Dry Rock (HDR) technology. However, the objective for using hydrothermal reservoirs requires a special stimulation technique to be able to produce considerably higher amounts of fluids compared to hydrocarbon reservoirs. In contrast to the HDR technology our aim was not to install a heat exchanger but to get access to formation fluids in the reservoir. The most important parameters in these experiments include fracture fluids volume, injection rate, viscosity (water with added polymers), the composition of chemical variants or adding proppants, and the selection of the depth interval to initiate new fractures. In the following, we summarize the stimulation experiments carried out over the recent years in the well Groß Schönebeck 3/90.

3.1 Sandstone Stimulation

The first stimulation experiments were more or less of conventional kind, i.e. on the basis of expertise of the hydrocarbon industry. Several experiments took place in January 2002 using proppant-gel-frac techniques in two intervals of the Rotliegend sandstones. Experiment design comprised the isolation of the bottom boundary of the interval of interest by filling the bottom of the well with sand. The top of the interval was sealed with a mechanical packer (figure 1). High viscosity fluid with proppant was employed for stimulation. Flow rates were increased significantly (see figure 2) and a fracture with a length of 150 m was generated due to this operation. The observed flow rates were not sufficient for economic power production (Zimmermann et al., 2003). Legarth et al. (2003) conclude that the experimental results were strongly influenced by the proppant properties during the treatment.

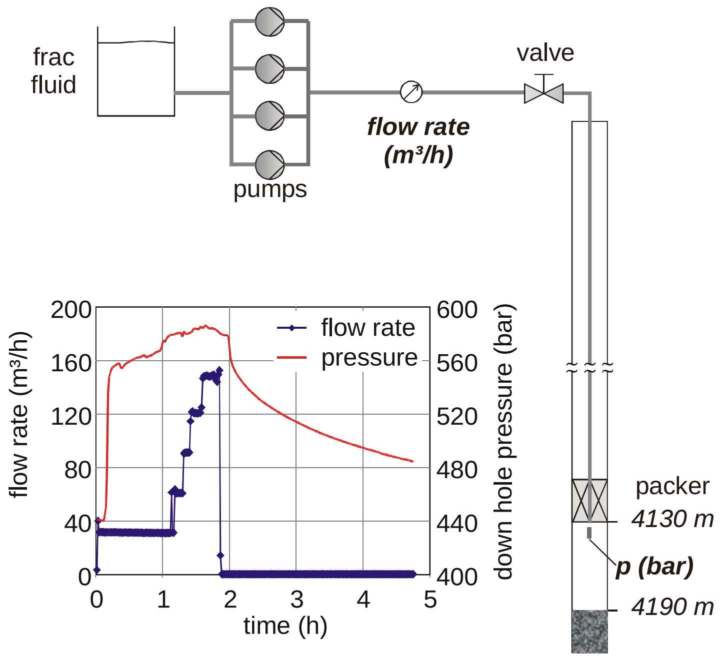

Figure 1: Technical concept of sandstone stimulation in the well Groß Schönebeck 3/90 in 2002. Bottom of the well is isolated with sand and the packer is set at the top of the interval. The graph shows wellhead pressure and fluid injection rate as a function of time.

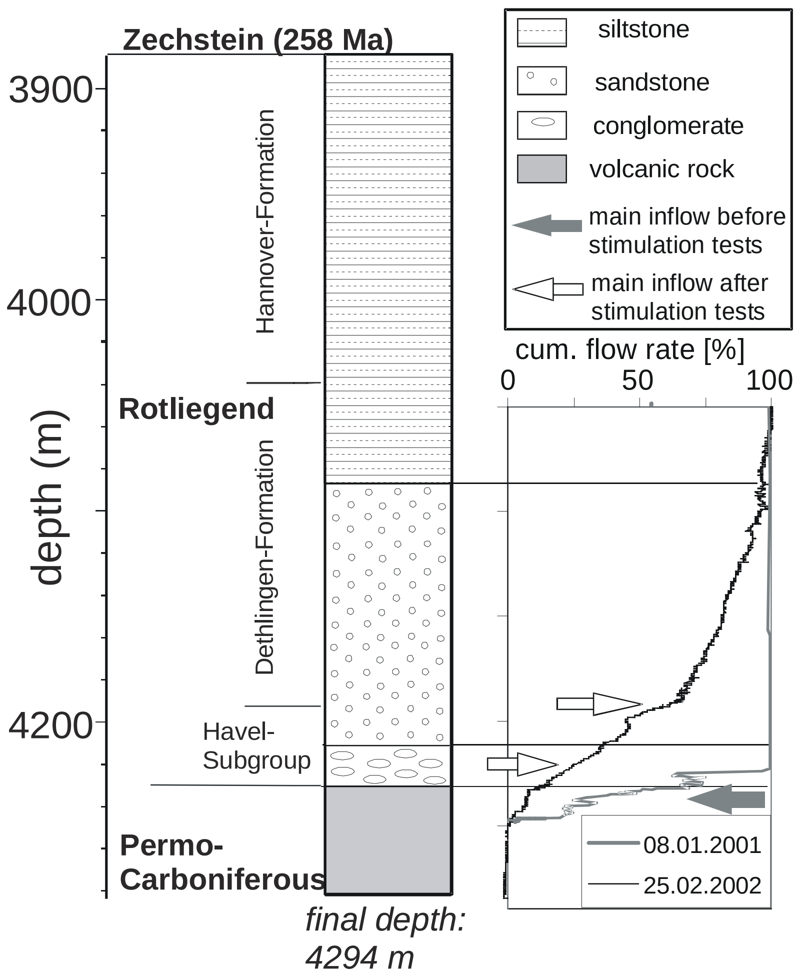

Figure 2: Lithology profile and cumulative flow measured with a flowmeter during short term lift tests to obtain the inflow zones.

Another parameter to improve the results is the volume of injected frac fluid in a forthcoming experiment. Therefore, the experiments were continued with a procedure injecting at least two orders higher volume into the reservoir.

To estimate the hydraulic parameters in more detail, a long-term pumping test was performed in summer 2002 (Zimmermann, 2004). 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 approx. 1 m³/h over a period of several weeks. In total, 700 m³ formation fluids were extracted. The draw down reached a constant level after 10 days, but steady state conditions were not reached until the end of the test (Figure 3). The productivity-index was estimated at pseudo steady state conditions to 0,6 $m^3 * h^{-1} * MPa^{-1}$.

Transmissibility of the productive formations was estimated from pressure build up during the shut-in time to 3,1 10^{-14} m^3. The minimum extension of the reservoir was calculated according to Carslaw & Jaeger (1959) from maximum radius of investigation to R= 617m (assuming matrix permeability = 3 x 10^{-16} m², porosity = 0,05, fluid viscosity = 4 x 10^{-4} Pa s, total compressibility = 5 x 10^{-10} 1/Pa).

Additionally, chemical composition of the produced fluids were determined (Wolfgramm et al., 2004); salinity of the formation fluid was 262 g/l at the end of the long term pumping test. In comparison with the former data the effect of the stimulation success in view of the further stimulation experiments could be estimated accurately.

3.2 Massive Waterfrac Treatment I

In January/February 2003 a massive waterfrac treatment was performed in whose progression a total amount of 4284 m³ fluid were injected under high pressure into the reservoir. In the first part a pressure step test with gradually increasing injection rates up to 24 l s^{-1} was performed. The results show that at a injection rate of 8 l s^{-1} the pressure increase is reduced due to an enhanced injectivity of the formation.

In a subsequent flow back test 250 m³ water was produced within 5 hours (Figure 4). This indicates in comparison with tests after the sandstone frac treatment a significant increase of productivity. Productivity index is above 4 $m^3 * h^{-1} * MPa^{-1}$ during the whole test. This indicates that the massive water injection had produced additional fractures, so that the experiment was noted successful. However, borehole breakouts took place resulting in an obstruction just at the upper part of the tested section at about 3900 m depth. Therefore, further technical borehole operations were necessary.

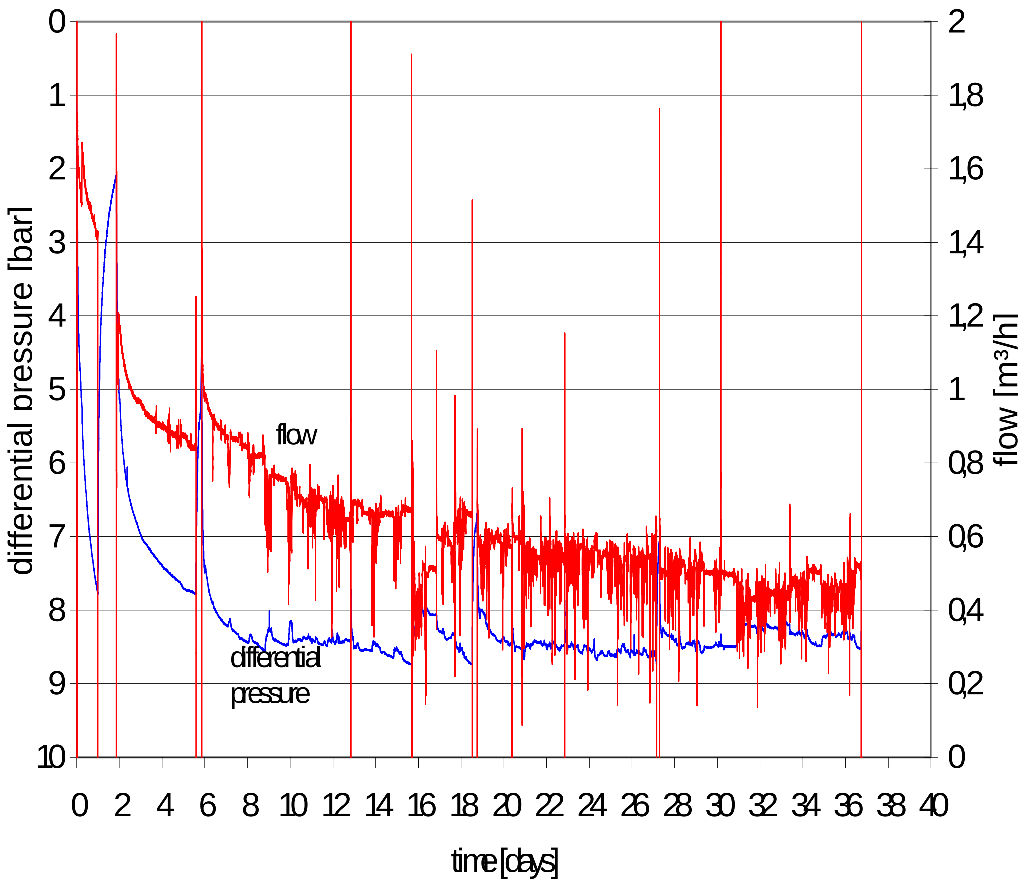

Figure 3: Flow rate and differential pressure during well test in 2002. Productivity index is 0,6 $m^3 * h^{-1} * MPa^{-1}$ at the end of the test.

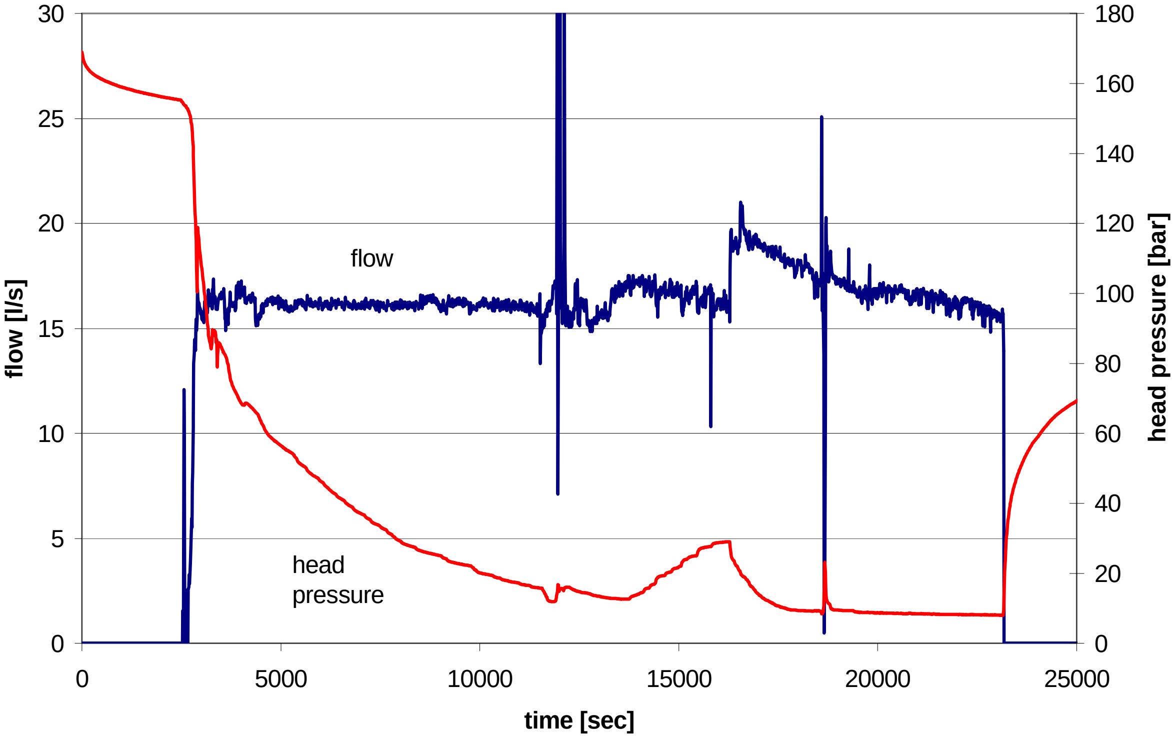

Figure 4: Flow and well head pressure at flow back test in March 2003. During the whole test the productivity index is above 4 $m^3 * h^{-1} * MPa^{-1}$.

3.3 Reopening, Deepening, and Liner Installation

In October 2003 the well was re-opened and deepened to 4309 m, and for stabilization of the well an additional liner from 3850 m down to the final depth was installed. Prior to the liner installation, an extensive logging program was performed to get information about the geological structure and the lithology of the borehole section of interest. FormationMicroImaging-Measurements show very clear the produced vertical fracture of 150 m height which was first observed by BoreHoleTeleviewer BHTV measurements after the sandstone frac treatment.

The liner was installed in the lower part beneath 4135 m installation depth with perforated tubes (diameter of holes 15 mm) to ensure the hydraulic contact to the formation. In the stabilized well the massive water frac experiment was continued in fall 2003.

3.4 Massive Waterfrac Treatment II

After the liner installation the massive injection treatment was continued with a pressure step test to obtain the opening of the fractures. Thereafter, a massive stimulation test of 30 ls^{-1} to 40 ls^{-1} over several days and with a short time of up to 80 ls^{-1} was performed.

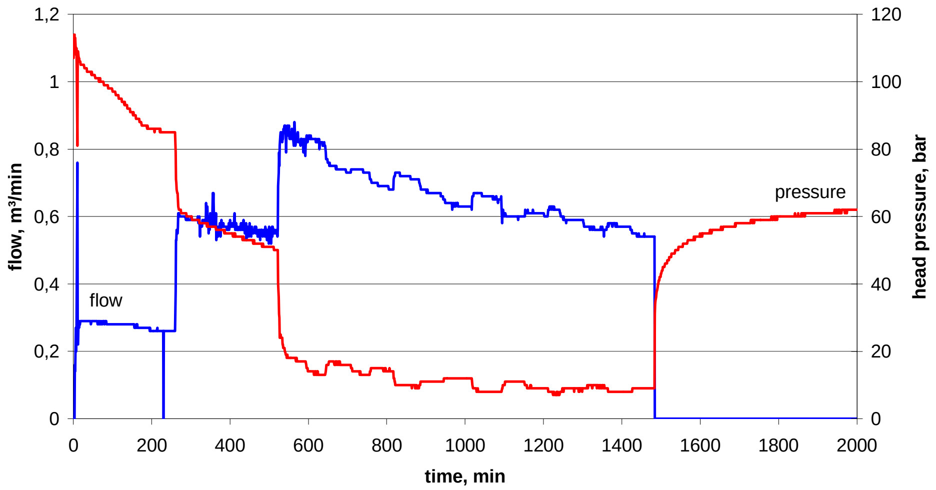

Figure 5: Flow and well head pressure at flow back test in December 2003

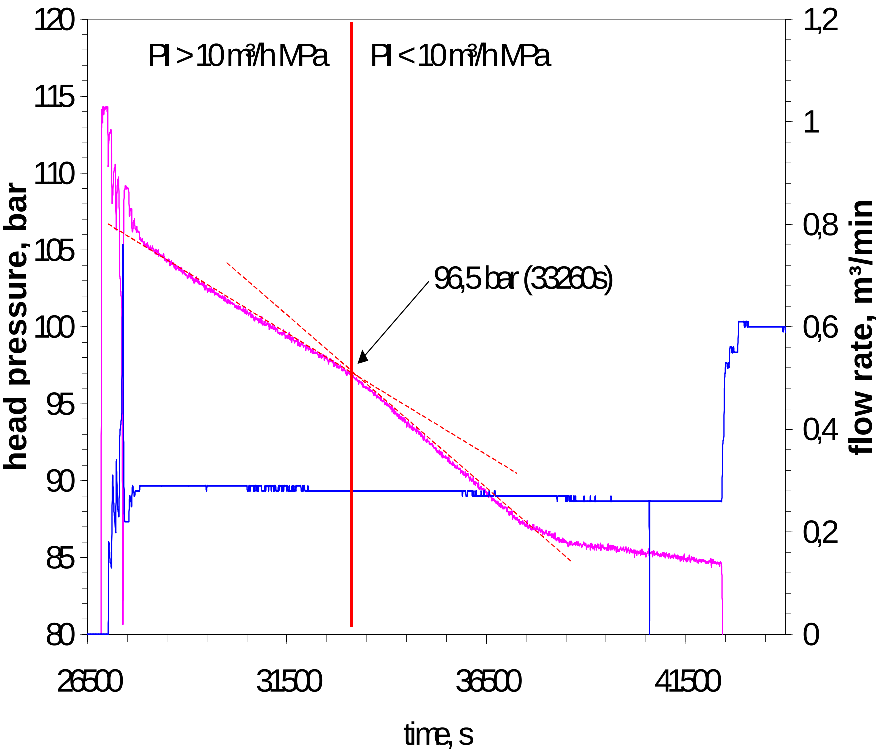

Figure 6: Fracture closure at well head pressure of 96,5 bar indicated by the change of slope during the first part of the flow back test in December 2003.

The pressure step test indicates multiple fracture generation and extension with opening and closure pressures between 60 and 88 bar above formation pressure. Within a 24 hours flow back test more than 900 m³ water was produced from the formation indicating another increase of productivity in comparison with former tests (Figure 5).

The data shows that the stimulation treatments yielded an increase of productivity up to 10 $m^3 * h^{-1} * MPa^{-1}$- determined at fracture closure pressure (Figure 6). This closure pressure could be observed by the change of the slope of the pressure decline curve. Which started from values above the fracture closure pressure. From this follows that self propping of the fracture did not occur in the sandstones.

According to model calculation the pressure data demonstrate, that a new artificial fracture was created. It spans vertically over a height of 120 m in north-south direction and extends horizontally at least 160 m into the formation. The mean fracture aperture is in the range of approximately 5mm.

CONCLUSIONS AND OUTLOOK

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.

The results reflect the learning curve from several reservoir treatments. These experiments are major steps towards developing a procedure to increase the thermal water productivity from a prior low permeable sedimentary reservoir. For "engineering" the reservoir we recommend a method of massive waterfrac with a proppant treatment at the end to ensure the opening of the fracture and long term stable width of the fracture.

The obtained values of productivity seem to show the feasibility of geothermal power production from a sedimentary geothermal reservoir.

The concept for power production from the Groß Schönebeck reservoir comprises a doublet of wells. The second well should be completed as a production well. The existing well can be used as an injection well.

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