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Current state of the EGS project Groß Schönebeck – drilling into the deep sedimentary geothermal reservoir

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ABSTRACT

In the context of the Geothermal Technology Program at GFZ, the former gas exploration well Groß Schönebeck 3/90 (50 km northeast of Berlin) was reopened and deepened to 4309 m depth. For the last 6 years, this well has served as a geothermal in-situ laboratory for in situ experiments and the development of stimulation concepts. The objective of these stimulation operations was to create secondary flow paths and to improve the inflow performance of the well.

The well makes the deep sedimentary Rotliegend reservoir accessible, which is characterized by water bearing porous and fractured rocks. To complete a potential doublet for power generation, the second well Groß Schönebeck 4/05 was drilled in late 2006. At pay-zone depth level the maximum distance between the two wells is approximately 500m. The most promising sandstone layers for stimulation were identified by measured porosity distribution, water saturation and calculated permeability data. This information is a prerequisite for the decision on perforation depths. Further experiments are forseen in 2007 now using both wells.

This article describes the challenges and experiences of drilling the geothermal research well into a deep sedimentary geothermal reservoir. The lessons learnt covers drilling large diameter in sheet silicate bearing rocks, directional drilling through and beneath salty formations, and various mud concepts with the goal of minimized formation damage.

1. INTRODUCTION

Increasing demand for renewable energies leads to the utilization of geothermal energy from areas with standard geothermal gradients as found in West- and Central-Europe. In such areas, it is necessary to increase the rate of energy recovery from depth by enhancing the geothermal system. There are mainly two basic technology concepts, which distinguish between dry rocks and water-bearing reservoirs. These concepts are:

- creating an artificial heat exchanger at depth and using surface water for heat extraction from mostly dry rocks, e.g., Soultz-sous-Forêts (Baumgärtner et al. 2004);

- creating artificial pathways at depth to enhance the water flow from water-bearing reservoir rocks, e.g., Groß Schönebeck (Huenges et al. 2004).

Both concepts are based on hydraulic fracturing techniques using variations in fluid pressure to design the reservoir. A review of several hydraulic fracturing methods was given by Economides and Nolte (1989) (see also Economides et al., 2002 and Entingh, 2000, and Huenges and Kohl, 2007).

Our study was performed in the former gas exploratory well Groß Schönebeck, which was re-opened and deepened to 4309 m depth to serve as a geothermal in-situ laboratory starting in December 2000. The purpose of the down-hole laboratory was the development of technologies to increase permeability of deep aquifers using hydraulic fracturing methods. The goal was to learn how to control the stimulation of a variety of rocks so that geothermal energy can be exploited from any kind of reservoir where it is needed. In addition to the pre-existing well, a second well was drilled in late 2006. The activities at the Groß Schönebeck site will culminate in the installation of a binary geothermal power plant.

Conditions imposed on geologic formations suitable for our studies were: (1) temperatures above 120°C, which implied a formation at depths greater than 3000 m; (2) large regional extent so that results from this project may be extrapolated to other similar areas, and (3) a variety of lithologies available for investigation. The wells at Groß Schönebeck give access to the Lower Permian Rotliegend formation, which entirely meets the above mentioned requirements.

Lower Permian siliciclastic sediments and volcanics are widespread strata throughout Central Europe forming deeply buried aquifers in the North German Basin with formation temperatures of up to 150°C. The average depth of these strata is 4000 m. The formation is well known as it has been extensively drilled for gas exploration and production. The wells cut through a typical sequence of geological formations, known in the North German Basin (Fig.1). 2370 m of Quaternary to Triassic sediments are underlain by 1492 m of Zechstein evaporites. The following section of the well comprises 400 m of Rotliegend siltstones, sandstones, conglomerates and 70 m of underlying volcanic rocks down to the final depth of 4309 m.

2. PREVIOUS HYDRAULIC EXPERIMENTS AT THE WELL GROß SCHÖNEBECK 3/90

The first well (GrSk 3/90), originally completed in 1990, was re-entered in 2000, hydraulically stimulated in 2002 and 2003, and tested in 2003, 2004 and 2005. Nine months after reopening the first well, a temperature of 149 ° C was measured at 4285 m depth. The formation pressure was determined using pressure logs after long term fluid level observations, reaching levels close to equilibrium 44.9 ± 0.3 MPa at 4220 m depth.

A series of stimulation experiments were performed using different fracturing concepts. First, open hole hydraulic proppant-gel fracturing treatments were conducted in two pre-selected sedimentary reservoir zones in Lower Permian sandstones at a depth of about 4 km. These proved on the one hand to be technically demanding, and on the other hand, less successful than expected due to a sub-optimal design resulting in formation damage. Nevertheless, the main inflow zones could be clearly identified. In a second step, massive waterfrac treatments were applied over the entire open hole interval of the well below 3874 m to the final depth at 4309 m. Pressure response analyses and well logs indicated the creation of vertical fractures and demonstrated a bilinear flow regime in the reservoir. Detailed accounts of stimulation experiments in the Rotliegend sandstones and volcanics were published by Zimmermann et al. (2003, 2005) and with the focus on pore pressure effects by Huenges et al. (2006).

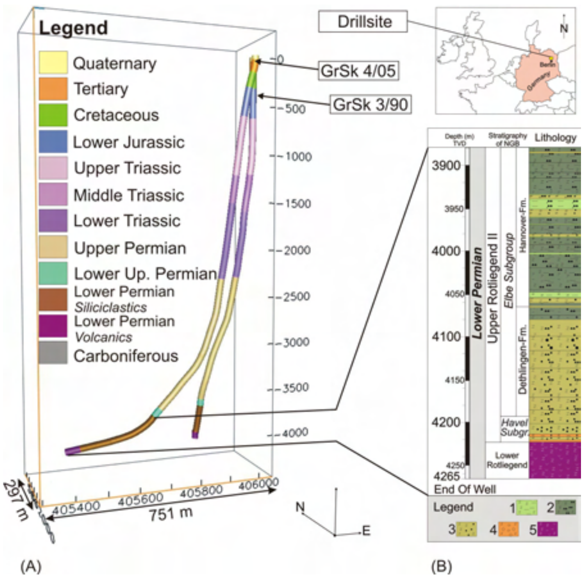

Figure 1: Location of the drilled doublet system and the geothermal aquifer in the Lower Permian of the NEGB. (A) Configuration of the geothermal doublet system. (B) Lithology of the Lower Permian along the recently drilled new well. Legend: 1-claystone, 2-siltstone, 3-fine to middle grained sandstone, 4-middle to coarse grained sandstone, 5-andesitic volcanic rock.

We can summarize that evidence of the creation and properties of vertical fractures was retrieved from logging and pressure response analyses and demonstrated a bilinear flow regime in the reservoir. The newly created enhanced geothermal system may be suitable for geothermal power production in a deep sedimentary reservoir. Therefore, the stimulation effect in terms of a productivity increase can be determined and improvements can be recommended for similar field experiments. The experimental work in the single well is now finished. The next step is to show that the fractures will stay open, and that a sustainable rate of fluid production can be demonstrated. This needs a second well.

Thermal modeling was used to choose the ideal geometry for the second hole to be drilled. For the conditions at Groß Schönebeck, a reservoir with some permeability, an arrangement of fractures aligned perpendicular to the line connecting the two wells (Fig. 2) was found most appropriate, as it does not increase the auxiliary energy requirements to drive the thermal water loop, and it has a low risk of a temperature short circuit of the system within 30 years utilization. This study implies special demand on the well path. Therefore, among other challenging tasks directional drilling was required for the second well.

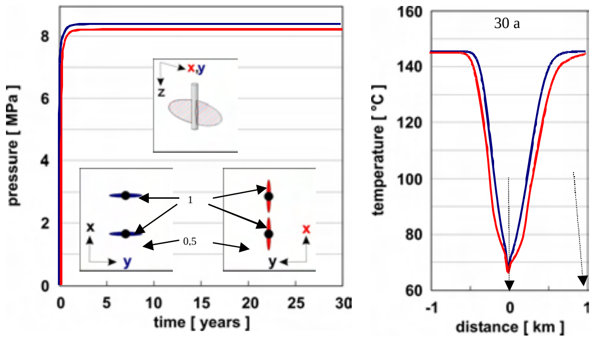

Figure 2: Thermal hydraulic models of the thermal water loop (75 m³/h) (frac orientation parallel and perpendicular to the connecting line of both wells) with a fracture half length of 250 m, respectively. Pressure vs. time within the injection well (left) and temperature distribution of a doublet with 1000 m distance of injection point to production point (marked by arrows) after 30 years (right). Fracture conductivity is assumed to be 1 Dm; transmissibility of the surrounding rocks is assumed to be 0.5 Dm. The fracture conductivity is consistent with the pressure transient analysis of the December 2004 experiment. The transmissibility value corresponds to the upper limit of the result of the field measurement (Zimmermann et al., 2007).

3. THE NEW WELL

The design and drilling of the second well (Figs. 1 and 3) considered the following issues (1) to (3): (1) the deep static water table of the reservoir and the respective withdrawal during production (housing for the submersible pump), which requires a large hole diameter, (2) the distance between the two wells of the doublet in the target horizon and the opportunities of increasing the inflow conditions by an inclined well and later by implementation of multiple fracs, by using the directional drilling techniques, and (3) a drilling mud concept, which avoids formation damage of the reservoir as much as possible.

3.1 Cementing

Total fluid loss occurred during the bottom up cementation of casing 16" x 13 3/8", which was performed with a mean slurry density of 1450 kg/m³. Uncontrolled hydrofracturing took place within Triassic limestone section. Thermal induced stress on the casing during hot water production had to be considered and casing damage had to be prevented which required a complete cementing along the whole profile. Therefore, squeeze cementation was performed from top of the well to the former cement infiltration zone. The successful placement of the cement was controlled by thermal logging.

3.2 Casing failure

After drilling 1600 m thick Upper Permian evaporites, a the 9 5/8" liner was installed that collapsed in the bottom region after reduction of the mud density from 2000 kg/m³ to 1060 kg/m³. The causes are not yet fully understood, as only casing material with certified quality was installed and the design was done according to the rules with a safety factor of more than 2 respecting the overburden pressure gradient. The problem was solved by replacement of the collapsed 9 5/8“ liner by a 7“x7 5/8“ liner after sidetracking. The loss of one casing dimension required the adjustment of the borehole design and the borehole was finalised with 5 7/8“ drilling of the geothermal reservoir in the Lower Permian section.

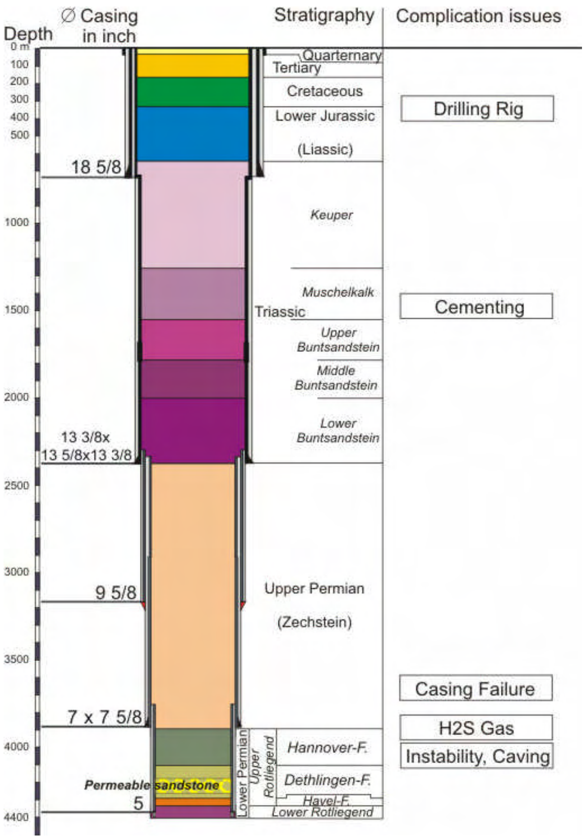

Figure 3: Design and stratigraphy of the well Groß Schönebeck 4/05 including spotlights of later discribed operations.

3.3 Borehole stability

Entering the reservoir sections below 3900 m the formation was drilled with a near-balanced mud density of 1.03 g/cm³ to avoid formation damage. However, caving at 3940 m caused interruption of the drilling operation. After cleaning of the wellbore, drilling could be continued at elevated mud pressure. The used slurry afterwards had a density of 1100 kg/m³, as was predicted by the modelling for stable conditions.

For this purpose, a fracture mechanics based numerical analysis of the influence of various mud pressures on the initiation of borehole breakouts was applied (Moeck and Backers, 2007). This analysis yielded an instability map for the 3,900 m level for geothermal well Groß Schönebeck GrSk4/05.

3.4 Appearance of gas with H_2S

Another reason for increasing the near-balanced mud weight was the occurrence of HC - gas with H_2S - content below the 7 5/8“ casing shoe (within fissured lowermost Upper Permian). To prevent gas inflow, the mud density was increased to 1,2 g/cm3. Due to the danger of differential sticking and formation damage the mud weight was slightly decreased in the further drilling operations.

3.5 Accessing the Reservoir

At the end the well followed its forseen path and target (Fig. 3) and a combined 5“ liner with an uncemented section of preperforated pipes at the bottom was installed down to the bottom at a depth of 4400 m. The borehole is now well prepared for the above mentioned further treatments.

In the target horizon in the Lower Permian, middle to fine grained sandstones of the Dethlingen Formation are found as confirmed by cuttings and well logs. The well is located at the flanc of a structural high of the sandstones. The Lower Permian sediments reach a thickness of 340 m. A highly permeable sandstone layer with a permeability up to 160 mD, lies within the succession and has a vertical thickness of 35 m. The inclination of the well by 45° increases the apparent thickness up to 70 m in the permeable sandstone. The well deviation is oriented in 288° to optimize the hydraulic frac design (Figs. 1 and 2). Since hydraulic fracs are parallel to the maximum horizontal stress direction S_{Hmax}, only a deviation in WNW-ESE direction enables the planned design of parallel fracs. Hydraulic fracs are planned in the volcanic rock and some in the sandstones. According to the above mentioned hydraulic-thermal modelling a distance between the bottoms of wells of more than 450 m is required to avoid a thermal breakthrough of the re-injected cooled water to the production well.

3.6 Logging operations at reservoir depth

The logging operations above reservoir depth level include caliper and gamma ray measurements. The Rotliegend profile was logged wireline with nuclear (Compensated Neutron, Spectral Pe Density & Spectral Gamma Ray), resistivity (Dual Laterolog, Micro Spherically Focused Log) and acoustic (Monopol Dipole Array) devices (Fig. 4). Tool sticking phenomena of the nuclear sondes were due to thick mudcake buildup at the permeable sandstone sections. To avoid having to recove a stuck nuclear tool it was decided to measure porosities after casing down the well with a cased hole measurement (Pulsed Neutron Decay) to calibrate the porosity data with the openhole logs. Resulting from these data a petrophysical composite log will be computed to identify the most promising sandstone layers and to decide finally on the perforation depths for the planned stimulations.

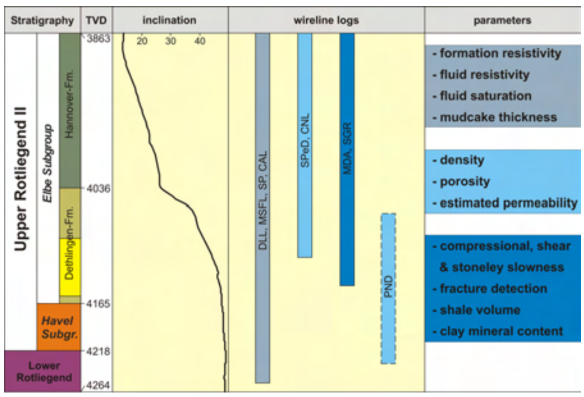

Figure 4: Wireline logging at the well Groß Schönebeck 4/05.

4. CONCLUSIONS

In the North East German Basin 4000 m deep Lower Permian sandstones and volcanic rocks are explored for geothermal energy production. A research strategy is developed and applied using the geothermal in situ laboratory Groß Schönebeck. The strategy realized until now consists of (I) re-using a former gas exploration well for logging and hydraulic stimulation campaigns, (II) understanding the reservoir behavior based on data recovery from hydraulic treatments, (III) optimizing the planned reservoir exploitation by analyzing the performance variances of well paths, (IV) complete the geothermal doublet system by drilling a new well, and in future (V) stimulation and testing the new well and installing a thermal water loop using the doublet and (VI) under sufficient reservoir conditions installing a binary geothermal power plant. The recovered experiences especially in (IV) show (1) that drilling a large hole diameter (23”) is feasible but challenging especially in sheet silicate dominated depth sections, (2) that directional drilling is a standard operation, and (3) that a variable mud concept can be applied in order react to unforeseen operation requirements without formation damage. All the three issues were successful realised and the lessons learnt offer essential knowledge for future drilling strategies in deep sedimentary geothermal systems especially in the Central European Basin System.

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