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Pressure dependent production efficiency of an Enhanced Geothermal System (EGS) – Stimulation results and implications for hydraulic fracture treatments

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SUMMARY

A series of stimulation experiments were carried out at the geothermal research well in Groß Schönebeck (EGrSk 3/90) located in the north-eastern part of Germany. The intended purpose of these experiments was to develop concepts for a productivity increase of the geothermal well to create an Enhanced Geothermal System (EGS). Two different kinds of stimulation types were performed. Hydraulic gel-proppant stimulations were conducted in sandstone sections with high initial permeability. Then a different fracturing concept was applied injecting high amounts of water. This waterfrac stimulation was realised in the entire open section including sandstones and volcanic rocks. Evidence of the creation and properties of a very long vertical fracture were retrieved from pressure response analyses demonstrating a bilinear flow regime. The production efficiency of the produced artificial fractures shows a strong dependence on reservoir pressure. At increased reservoir pressure the artificial fractures of all stimulated intervals are highly conductive and subsequently get less conductive during pressure decline. Hence the range of a suitable reservoir pressure is constrained by this fracture efficiency and limits the usage of this well as an injection well for geothermal power production.

INTRODUCTION

Sustainable and environmentally friendly energy can be generated from the conversion of Earth's heat (from formation fluids) into electricity. The preconditions for an economic generation of geothermal electricity are sufficiently high temperatures and flow rates of more than 50 m^3/h and 150 °C (Köhler & Saadat, 2003). The required temperature for this purpose can be found in the North German Basin at 4000 m to 5000 m depth. At this depth the initial permeability of the rocks is generally insufficient for the necessary flow rates. However, stimulation operations to improve the near well bore regions can lead to a sufficient productivity increase. These systems are generally called Enhanced Geothermal Systems (EGS) and can get commercially suitable after stimulation treatments to enhance the productivity.

Geothermal power production is based on (at least) two deep boreholes (a doublet), a sustainable thermal water cycle and a power plant on the surface (e.g. Köhler, 2005). In the first borehole (production borehole), thermal water is produced from a deep reservoir and conducted to the power plant where its heat is transferred. Afterwards, the thermal water is injected in the second borehole (injection borehole) and returned to the reservoir.

Concepts 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 extend fractures. These procedures are well known in hydrocarbon industry (e.g. Economides & Nolte, 1989) as well as in the Hot Dry Rock (HDR) technology (Hettkamp et al., 2004; Baumgärtner et al. 2004; Schindler et al., 2008). However, the objective for using hydrothermal reservoirs requires a special stimulation technique to be able to produce considerable higher amounts of fluids compared to hydrocarbon reservoirs. In contrast to the HDR technology, it wasn't the aim to create an underground 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 added proppants, and the selection of the depth interval to initiate new fractures. In the following, we evaluate the stimulation experiments and its impacts on the production efficiency of the reservoir with special emphasis on productivity and injectivity of the well as a function of reservoir pressure. The outcome of this evaluation will have a direct implication for the further use of this well.

GEOLOGY AND WELL HISTORY

The site used for this study Groß Schönebeck is located 50 km northeast of Berlin. This former gas well EGrSk 3/90 drilled in 1990 was re-opened and deepened to 4294 m at the end of the year 2000 to get access to the Rotliegend formation (Fig. 1). Here, hydrothermal aquifers can be accessed with formation fluids of 150°C and porosities of up to 10 % (Huenges & Hurter, 2002). The well was therefore selected as an in situ laboratory for scientific investigations on geothermal power production. Experiments in this in situ geothermal laboratory should lead to a reliable technology for sufficient production of deep fluids in such reservoirs.

The well encounters the typical sequence of various geological formations known in the North German Basin. A series of 2370 m of Quarternary to Triassic sediments is underlain by 1492 m of the Zechstein salinar (evaporatic rocks). The following section of this well, which was foreseen for testing, comprises 400 m of Rotliegend formation (siltstones, Dethlingen sandstones, conglomerates and 60 m of underlying volcanic rocks) up to the final depth of 4294 m (Huenges et al., 2002; Holl et al., 2004). This section below 3874 m was an open-hole section at times of the intended stimulation treatments of the well with access to the reservoir rocks. The main targets are sandstones of the Upper Rotliegend (Dethlingen Formation/Lower Elbe subgroup) as well as the volcanic rocks (andesites) of the Lower Rotliegend, where permeability is mainly due to connected fractures. The Dethlingen sandstones represent an effective reservoir horizon with a porosity of 8-10 % and a permeability of 10-100 mD (Trautwein & Huenges, 2005). The Elbe-Basis-sandstone as the lower part of the Dethlingen Formation exists in NE Brandenburg as a well sorted middle grained to fine grained sandstone, which has been deposited in a fluviatile setting. The effective reservoir thickness is approximately 80 m.

In 2003 the open hole section had to be cased with a perforated liner due to instabilities of the borehole wall in the siltstone layers. During this treatment the well was deepened to 4309 m and reached the top of the carboniferous.

DEVELOPMENT OF PRODUCTIVITY AND INJECTIVITY OF THE WELL

The productivity index and injectivity index are defined as the ratio between flowrate and pressure change in the reservoir during water production, respectively water injection. The production efficiency of a stimulation treatment can be quantified by the change of this index. But one has to take into account that this ratio generally dependents on pressure changes in the reservoir and the total fluid volume involved. Therefore, a comparison of hydraulic test results to quantify the stimulation achievement should be drawn under similar test conditions. For all following tests these conditions are summarized in Table 1.

Two different stimulation techniques were applied, which were specially designed according to the different rock properties. In the sandstone layers with their high permeability hydraulic fracture stimulations in isolated intervals were performed using high viscous gel and proppants. In the low permeability volcanic rocks waterfrac stimulations with high flow rates were carried out. Due to the high flow rates necessary for the waterfrac stimulation it had to be performed in the whole open section of the well, because frictional pressure increase due to a packer system in conjunction with a tubing of reduced diameter prevent high flow rates. Hence the waterfrac stimulation included the volcanic rocks as well as the sandstone layers and interpretation of the success of the waterfrac stimulation can hardly distinguish between the two rock types, because fracturing took place in both rock types. But the achieved contribution of each layer can be determined by flow and temperature logs and hence yields the individual production efficiency.

The initial hydraulic condition of the well was tested with a production test at the whole open hole section between 3874 m to 4294 m. The resulting productivity index achieved 0.97 $m^3/(h\ MPa)$ at maximum pressure drawdown. Subsequently, a flow log was run which showed outflow of the conglomerates and the volcanic sequences of the reservoir. The rocks of the Rotliegend Sandstones intended for use as the geothermal reservoir were nearly impermeable (Huenges et al., 2002; Zimmermann et al., 2003). The reason for this impermeable sandstone section is believed to be the mud infiltration during the long standstill period of approximately 10 years. Permeability measurements on cores from this section of the well showed mean values of 10^{-14} m^2 (10 mD) and documented the general usability of these reservoir rocks (Trautwein, 2005; Trautwein & Huenges, 2005). Transmissibility was calculated from the shut-in period of the initial test and estimated to 4 – 6 x 10^{-14} m^3 (0.04 – 0.06 Dm). This value reflects the transmissibility of the conglomerates and volcanic rocks, which are merely due to natural fractures.

The first stimulation experiments were gel-proppant stimulations in two isolated intervals of the Rotliegend sandstones (Zimmermann et al., 2003; Legarth et al., 2005). Visualisation by Borehole Televiewer (BHTV) and Formation Micro Imager (FMI) confirmed the creation of an open vertical fracture with a height of more than 100 m and in the direction of the maximum horizontal stress (S_H = 18.5° ± 3.7°) (Holl et al., 2003; 2004). The productivity index could be raised 2.13 $m^3/(h\ MPa)$ due to the stimulation treatments (Zimmermann et al., 2003). Compared to the previous test this result indicates a doubling of the productivity index of the well. Legarth et al. (2003) conclude that the limited achievement was strongly influenced by the proppant properties during the treatment and prevented a better result of the stimulation treatments.

To determine the hydraulic parameters of the stimulated reservoir in more detail and to obtain stable conditions over a longer period, a long-term production test was performed in summer 2002 (Zimmermann, 2004; Reinicke et al., 2005). The productivity-index was estimated at pseudo steady state conditions to 0.59 $m^3/(h\ MPa)$. Transmissibility of the productive formations was estimated from pressure build up towards the end of the shut-in to assure pseudo radial flow conditions and was calculated to 3.1 10^{-14} m^3. This low transmissibility suggests that the stimulated sections have no connection to the high permeable sandstones.

The first waterfrac treatment started in January 2003 with a moderate injection test. The observed injectivity index of 0.83 $m^3/(h\ MPa)$ corresponds to the productivity derived in the aforementioned production test at similar low difference pressure. For this reason it can be assumed that the hydraulic response of the reservoir is similar for production and injection for low pressure changes (decreasing for injection as well as increasing for production).

During the first part of the waterfrac treatment a total amount of 4284 m^3 fluid was injected under high pressure into the reservoir. At the beginning a pressure step test with gradually increasing injection rates up to 24 $l\ s^{-1}$ was performed. At the injection rate of 8 $l\ s^{-1}$ pressure increase reduces due to an enhanced injectivity of the formation. This effect can be interpreted as a mechanical reaction of the rock due to an opening of the existing generated artificial fractures as well as the extension of pre-existing fracture in the conglomerates and volcanic rocks at the bottom of the well (Huenges et al., 2006).

In the subsequent flow back test a significant increase of productivity could be achieved (Zimmermann et al., 2005), which was above 4 $m^3/(h\ MPa)$ during the whole test. This is an indication that the massive water injection produced additional fractures, so that the experiment was rated successful and represented roughly another doubling of the productivity index.

The waterfrac stimulation was continued with flowrates between 108 m^3/h and 144 m^3/h and a total injection volume of 7291 m^3. The pressure step rate test indicates multiple fracture opening events. Fracture closure pressure was determined by pressure decline analyses during shut-in at 6.4 MPa above formation pressure. In the following we discuss the result of this stimulation treatment in terms of pressure dependent productivity efficiency.

PRESSURE DEPENDENCE OF STIMULATION RESULTS

In general, the production efficiency of produced artificial fractures dependent on reservoir pressure changes. Hence, this dependence will be discussed in this section, because it is a crucial issue for the further use of this well in a geothermal doublet. Two cases will be discussed which represent the final reservoir conditions of the well: high increased reservoir pressure during a flow back test and low increased reservoir pressure during an injection experiment.

Production efficiency at high reservoir pressure

After the last hydraulic stimulation treatment in the well a flow back test was performed with a subsequent shut-in followed by a second flow back to reduce the remaining well head pressure. Within the first part of the test of 24 hours a total amount of 859 m^3 of water was produced from the formation indicating another increase of productivity in comparison with former tests (Fig. 2). The results show that the stimulation treatments yielded an increase of productivity up to 14 $m^3/(h\ MPa)$ determined at fracture equilibrium pressure of approximately 53 MPa, equivalent to a formation pressure increase of 9.8

MPa. The productivity index decreases with decreasing difference pressure giving a clear indication of a closing fracture (Fig. 2). Hence it can be concluded that a self propping effect due to shear displacement is nonexistent for the fractures of the Rotliegend sandstones and only residual fracture conductivity remains.

At the end of stable flow conditions at a flow rate of 50 m^3/h the remaining productivity index is 7.5 $m^3/(h\ MPa)$ at a formation pressure increase of 6.5 MPa, which corresponds nearly to another doubling.

The pressure response of the flow-back test, the subsequent shut-in and an additional flow-back reveal a bilinear flow signature (Fig. 3 and Fig. 4)($p \sim t^{0.25}$; according to Cinco-Ley & Samaniego-V. (1981)) during the first part of the test. At the end of the shut-in the derivative pressure signature achieves an almost constant level indicating a pseudo radial flow response ($p \sim \ln t$; e.g. Horne, 1995). From the maximum derivative pressure the maximum transmissibility could be estimated to 6.5×10^{-14} m^3 (0.065 Dm). Fracture conductivity was calculated according to the bilinear flow analysis to 4×10^{-13} m^3 (0.4 Dm), the corresponding fracture half length is 142 m.

Production efficiency at low reservoir pressure

To obtain the production efficiency of the reservoir rock at low pressure increase a long term injection experiment was carried out to obtain the hydraulic parameters of the reservoir and the fractures. The duration was scheduled to reach pseudo radial flow conditions and potential boundaries of the compartment. Furthermore, the longer testing time yields results with higher accuracy and higher reliability. During 18 days 3091 m^3 of preconditioned water was injected into the reservoir with density of 1000 kg/m^3 and pH-value lower than 5 to avoid iron scaling. The mean flow rate was set to 7.2 m^3/h over the whole time (Fig. 5). This limitation of the flow rate was due to the fact that a mechanical reaction of the rock, i.e. hydraulic fracturing, has to be avoided to obtain the pure hydraulic behaviour of the reservoir at low difference pressure. Furthermore, at low difference pressure hydraulic parameters of this injection test are comparable to an equivalent production test. The injectivity index was calculated to 2.02 $m^3/(h\ MPa)$ at the end of the injection phase at an increased reservoir pressure of 3.6 MPa. After injection the well was shut in and the pressure response was monitored over additional 76 days. At the end of the shut-in a well head pressure of 4.5 MPa remained due to buoyancy of the injected water. This remaining well head pressure was used to move on with a short flow back test in conjunction with temperature logging to obtain the inflow horizons of the reservoir. The production rate was set to 7.2 m^3/h just like before the injection rate to achieve comparable results. The temperature log, which was run during production, shows inflow from the bottom of the well appearing in the log profile as a change of slope (Fig. 6). Due to the obstruction below 4260 m the measured bottom of the interval was limited to 4255 m. The most significant change in the temperature profile and hence the most productive inflow was detected from 4212 m to the bottom at 4255 m yielding an effective inflow interval of 43 m. The limitation of this inflow to the conglomerates and volcanic rocks reveals that the contribution of the stimulated intervals of the sandstone layers due to the proppant frac treatment can almost be neglected at low difference pressures, i.e. the artificial sandstone fractures are closed at these conditions.

Well test analysis was carried out for the injection time and the subsequent shut-in time. Due to the signature of the pressure curve during injection and shut-in (Fig. 7) a model with a finite conductive vertical fracture and homogeneous reservoir conditions was applied. Since no indication of any boundary effects was visible in the pressure response towards the end of the test an infinite reservoir model was assumed. The pressure versus time curve and the derivative versus time curve showed quarter slopes in the log-log representation indicating a bilinear flow behaviour with a finite conductive vertical fracture in the reservoir (e.g. Cinco-Ley & Samaniego-V. (1981)). Toward the end the pressure derivative curve starts to converge to a horizontal line indicating the beginning of pseudo-radial flow and hence enables the calculation of the reservoir transmissibility.

From the bilinear flow analysis the fracture conductivity was calculated to 7.8 x 10^{-13} m^3 (0.78 Dm) during injection and to 9.6 x 10^{-13} m^3 (0.98 Dm) during shut-in. These values document high fracture conductivities, which can be related to the conglomerates and the volcanic rocks, and which remain stable especially during the shut-in with decreasing difference pressure. From this it follows that a self propping effect due to shear displacement keeps the fractures open in the lower part of the well. The corresponding fracture half length of the vertical fracture was estimated to 309 m and 255 m respectively. These half lengths are longer than expected from well test analysis after the waterfrac treatment at increased reservoir pressure with a calculated fracture half length of 142 m. Hence, it can be concluded that due to the fracture treatment a natural fracture system was connected. The transmissibility is about 4 x 10^{-14} m^3 (0.04 Dm) for both periods. The radius of investigation (e.g. Lee (1981)) was calculated to 527 m for the injection time after 18 days of injection; for the shut-in period of 76 days the radius of investigation reached 1100 m.

RESULTS OF FRACTURE SIMULATION

The simulation of the last hydraulic stimulation in the well displays the achieved geometry of all stimulation treatments, since the last treatment was performed in the open hole which includes the previously stimulated intervals. Hence all previous stimulated sections are affected by this last treatment and the geometry reflects an equivalent model of several artificial fractures.

The fracturing process was modelled with the three dimensional fracture simulator FRACPRO™ (Cleary, 1994; Cleary et al., 1983). The aim was to model the fracture dimensions by matching the net treatment pressures (Fig. 8). A detailed description of this analysis can be found in Legarth (2003). A reasonable pressure match of the real-data represents one plausible solution for the fracturing process and fracture geometry in reality. Determining fracture dimensions and geometry by modelling is important in order to set up the subsequent production schedule and as real-time modelling with the applied simulator becomes possible to optimise fracture and treatment design on site.

According to model calculation the pressure data of the stimulation treatment demonstrated the existence of an artificial fracture. Assuming one single vertical fracture, it spans vertically over a height of 100 m in north-south direction and extends horizontally at least 160 m into the formation (Fig. 9 and Fig. 10). The mean fracture aperture is in the range of approximately 5 mm during the stimulation treatment at an injecting flow rate of 108 m^3/h.

INTERPRETATION AND DISCUSSION

The initial production test before the stimulation treatments showed inflow only from the volcanic rock section of the reservoir. Since these rocks only have negligible matrix permeability this inflow is due to natural fractures of the conglomerates and volcanic rocks. The sandstone layers were nearly impermeable due to drilling induced near well bore damages referred to as well bore skin.

After stimulation treatments of the sandstones a flow log showed additional inflow from the sandstones. Furthermore the productivity index had increased (see Tab. 1). At low difference pressure the situation is different: the inflow from the sandstones decreases and the artificial fractures close (Fig. 11; bottom). Hence the productivity index is similar to that of the initial situation. This interpretation is supported by the determination of the associated transmissibility before and after stimulation, which shows similar values.

Transmissibility was calculated from shut-in after production tests and represents in both cases a value at low difference pressure.

Then two waterfrac stimulations were performed in the open section of the well which included the sandstone layers and the volcanic rocks. These stimulation treatments led to an additional access to the sandstone intervals and the volcanic rocks in the vicinity of the borehole due to the generation of additional artificial fractures.

After these waterfrac stimulations the effect in the sandstones is twofold: at high difference pressure the artificial fractures give access to the sandstone reservoir with a corresponding fracture half length of 142 m according to the hydraulic test results and 160 m according to fracture simulation. This leads to an additional pressure dependent increase in productivity index and hence enables the access to the reservoir (Fig. 11; mid and top). During high increased formation pressure above the equilibrium pressure all fractures including the artificial fractures in the sandstones as well as the natural and artificial fractures in the conglomerates and in the volcanics are open yielding an injectivity index of approximately 14 m^3/(h MPa)(Fig. 11; top). At low difference pressure the fracture half lengths and the fracture apertures are reduced, so most parts of the fractures are not effective and the link to the reservoir rocks of the sandstone layers is disconnected again. Only in the near vicinity of the well the fractures are effective and improve the access to the borehole. But this is only a skin reduction and is limited to the near borehole environment and hence does not transcend the zone of reduced permeability to the undisturbed sandstone reservoir. This interpretation is supported by the calculated transmissibility, which has not changed substantially after the stimulation treatments and is more than ten times lower as being expected for these high permeable sandstones.

In the conglomerates and the volcanic rocks at the bottom of the well new additional fractures were created. At low difference pressure only these sections give a contribution to the transmissibility. According to the low matrix permeability of these rocks this contribution is low and only the fracture system is effective. This interpretation is supported by the result of temperature logging during a production test, which showed only inflow from the conglomerates and the volcanic rock. The calculated extension of the fracture system is approximately 300 m and hence a nearly doubled value if compared to the previous analysis at high difference pressure. A most likely explanation of this outcome is the connection to a natural fracture system.

The results of hydraulic testing reveal that the effect of self propping of the stimulated fractures is different in the sandstone section and in the volcanic rocks. Self propping of a stimulated fracture presumes a shear displacement of the given fracture plane due to differential stress and preexisting natural fractures. The state of stress is normal to strike slip faulting with a differential stress in the order of 50 MPa in the sandstones and 30 MPa in the volcanic rocks. (S_v = 105 MPa; S_H = 90-100 MPa; S_h = 55 MPa (sandstones); S_h = 75 MPa (volcanics)). S_H was calculated for the sandstones by fracture mechanics modelling (Moeck et al., 2008) and is assumed similar in the volcanic rocks. S_h is approximately equal to fracture opening/closure pressure and was determined in the sandstone section by a leak-off test (Huenges et al., 2006). Due to operational limitations a leak-off test in the volcanics section exclusively was not possible, but it could be performed in the adjacent well located in the same reservoir compartment.

The flow characteristics indicated that the sustainability of hydraulic fracturing efficiency is different for the treated rock types. It is most likely that volcanic rocks consist of natural fractures, but we have no evidence for this, because no image logs were run in this section. Opposite to this, core samples of these sandstones do not show open natural fractures, only mineralised fissures are visible. Hence we conclude that a naturally fractured regime supports the shear displacement in the volcanic rocks during the hydraulic fracturing process. In case no natural open fractures exist like in the sandstone section, hydraulic fracturing is dominantly a tensile fracturing process and not sustainable. These considerations are in line with the aforementioned results of the hydraulic stimulation treatments, even if the differential stress in the sandstones is higher than in the volcanic rocks.

CONCLUSIONS

Enhanced geothermal systems (EGS) are engineered reservoirs that have been created to extract economical amounts of heat from low permeability and/or porosity geothermal resources. This includes all geothermal resources that are currently not in commercial production and require stimulation or enhancement. For these purposes we used the former gas exploration well in Groß Schönebeck as a down-hole geothermal laboratory.

The results reflect the learning curve from several reservoir hydraulic stimulation treatments. These experiments are major steps towards developing a procedure to increase the thermal water productivity from a prior low permeable sedimentary reservoir. The obtained values of productivity appear to indicate the feasibility of geothermal power production from a sedimentary geothermal reservoir.

The pressure dependence of productivity and injectivity of the geothermal reservoir queries the sustainability of the created artificial fractures. In volcanic rocks with natural fractures one can expect a self propping effect due to shear displacement keeping the artificial fractures open after reservoir pressure release. In sedimentary rocks this self propping can not be expected in general.

Immediate consequence of this is that the fractures close after the injection pressure is reduced. Only a proppant package can avoid closure of the produced fractures, therefore stimulations in sedimentary rock should comprise high proppant concentration to obtain a multi layer proppant package and hence a high fracture conductivity.

The results of pressure dependence production efficiency of the reservoir exclude the usage of this well as a production well. On the other hand this well is suitable as an injection well within a doublet system due to an increased injectivity as a result of the stimulated fractures remaining open at increased reservoir pressure.

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Figure captions:

Figure 1: Location and geological profile of the well EGrSk 3/90

Figure 2: Trend of productivity index during first flow back test. At the end of the stable flow rate (approx. after 11 hours of flow) the remaining productivity index is 7.5 $m^3/(h\ MPa)$ at the flow rate of 50 m^3/h.

Figure 3: Pressure match of flow back test to obtain hydraulic parameters like fracture length and formation transmissibility

Figure 4: Log-log response of pressure and derivative as function of superposition time of flow back test (Figure 3). The upper curve represents pressure, the lower curve pressure derivative with maximum transmissibility derived at end of derivative.

Figure 5: Flow and well head pressure during the long term moderate injection experiment and adjacent shut-in period.

Figure 6: Temperature profiles before (static) and during production (dynamic) in the open section of the well. The temperature changes before production are due to the injection of cold water during the stimulation treatments.

Figure 7: Log-log representation of the pressure response and its derivative during injection phase (top) and shut-in phase (bottom) of the experiment. The continuous lines represent the calculated results from well test analysis.

Figure 8: Pressures and flow rates during the waterfrac stimulation

Figure 9: Calculated geometry of generated fracture during the waterfrac stimulation

Figure 10: Final geometry of the generated fracture and stress and permeability profile of the waterfrac stimulation

Figure 11: Pressure dependent production efficiency of inflow into the reservoir rock (II = injectivity index). Top: all artificial fractures (from stimulation) are open at reservoir pressure equal to fracture equilibrium pressure. Mid: residual opening of artificial

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Table 1: Data from hydraulic tests in EGrSk3/90 (PI = productivity index; II = injectivity index).

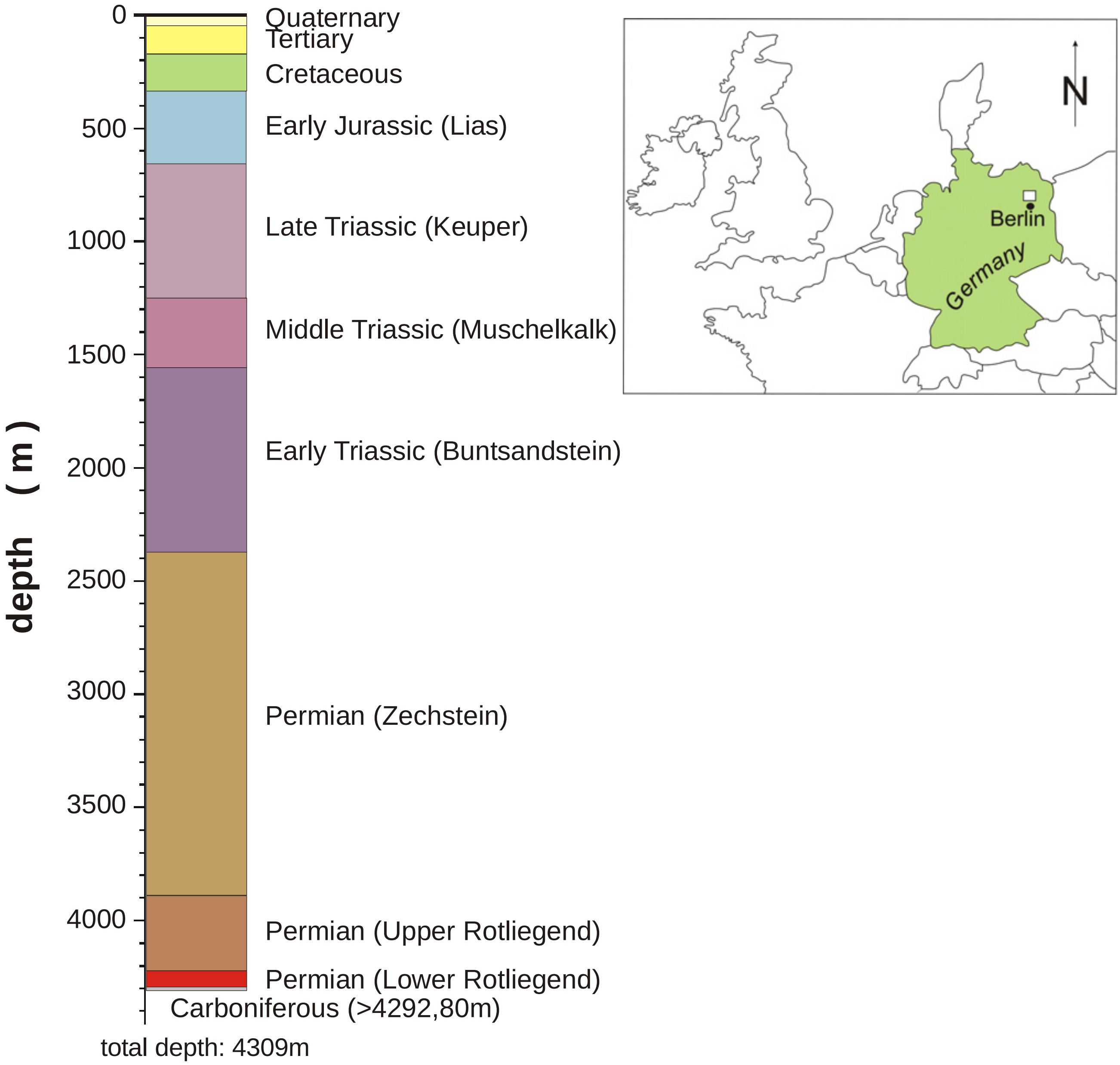


Figure 1: Location and geological profile of the well EGrSk 3/90

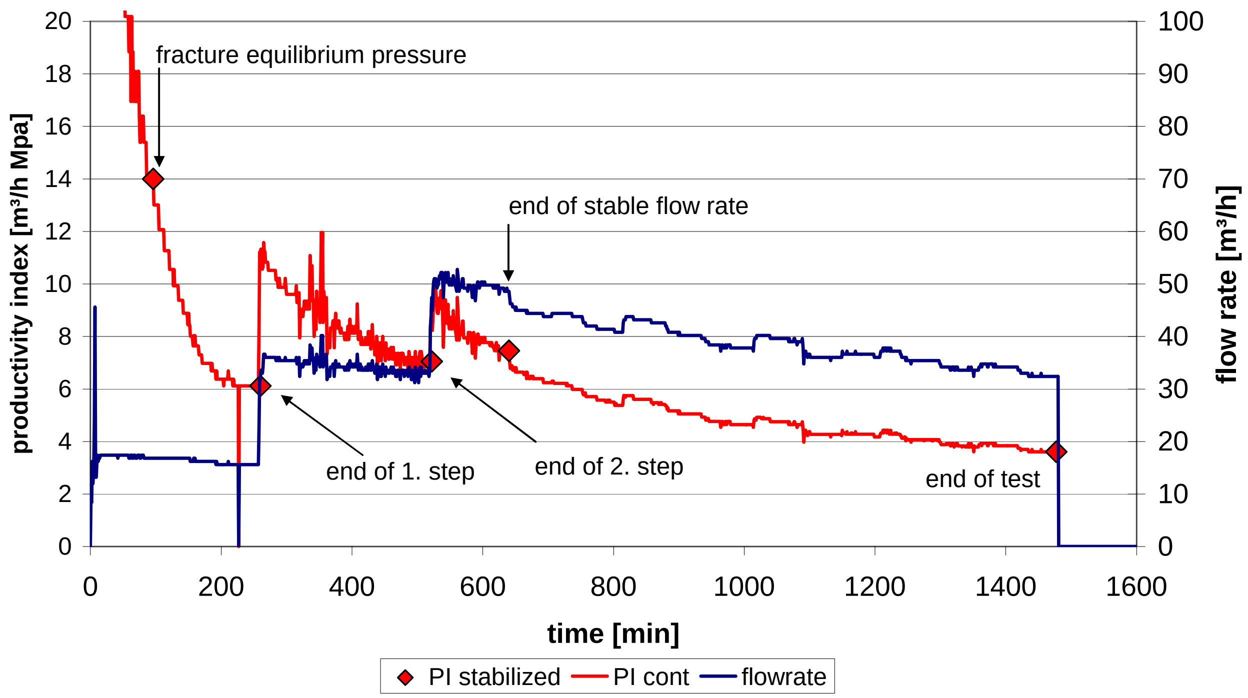


Figure 2: Trend of productivity index during first flow back test. At the end of the stable flow rate (approx. after 11 hours of flow) the remaining productivity index is 7.5 $m^3/(h$ MPa) at the flow rate of 50 m^3/h.

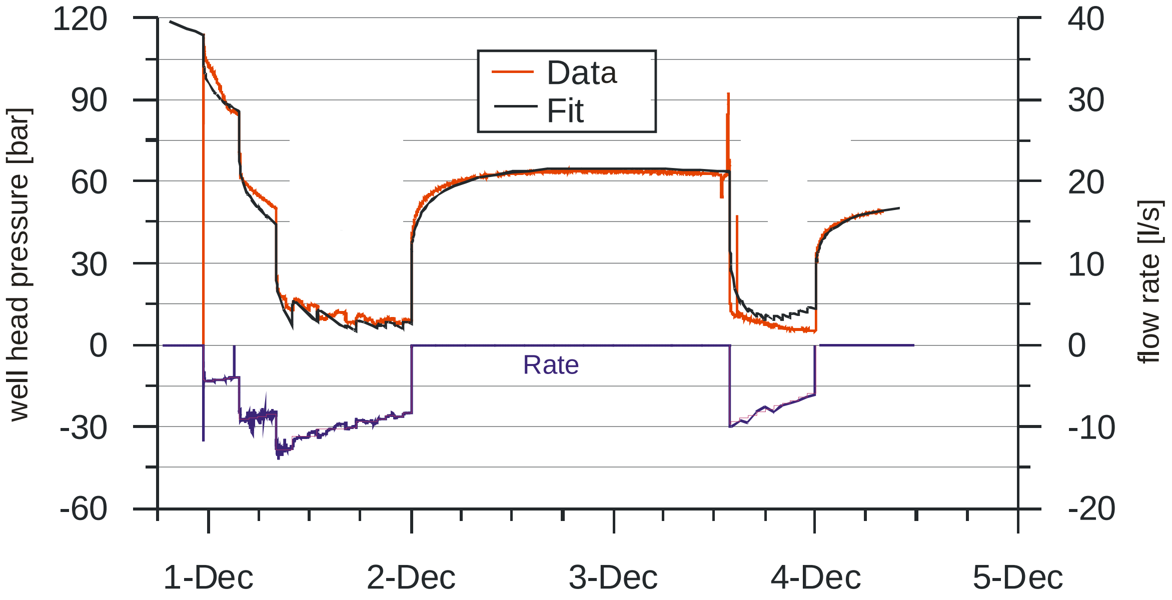
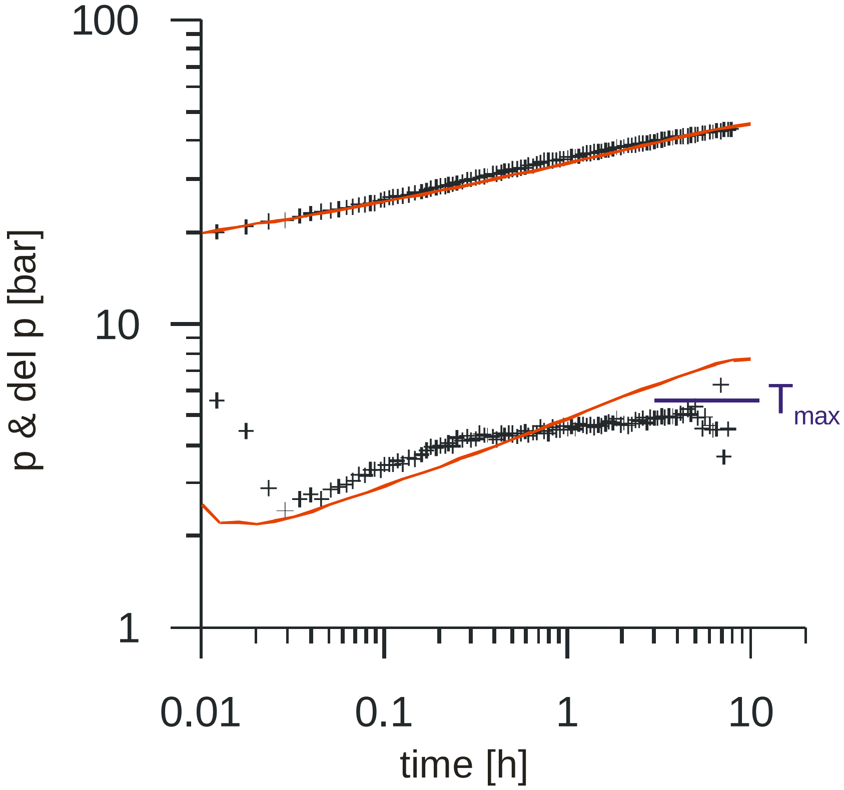


Figure 3: Pressure match of flow back test to obtain hydraulic parameters like fracture length and formation transmissibility



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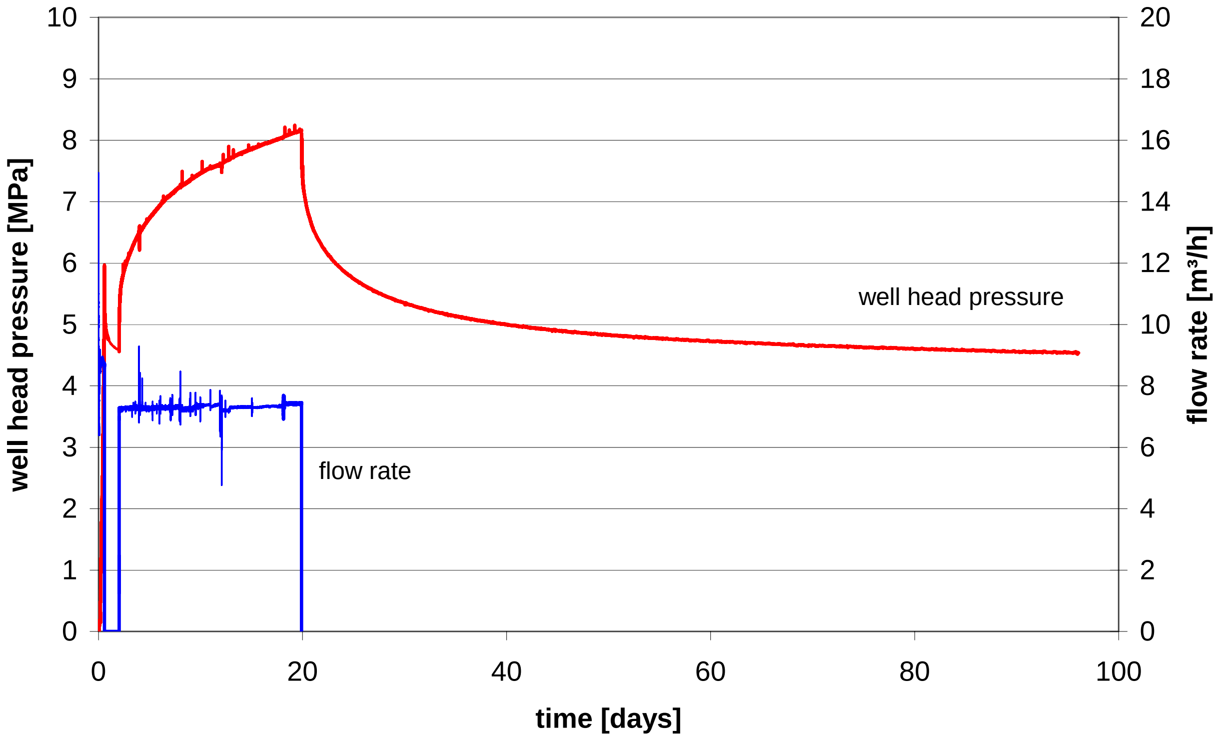


Figure 5: Flow and well head pressure during the long term moderate injection experiment and adjacent shut-in period.

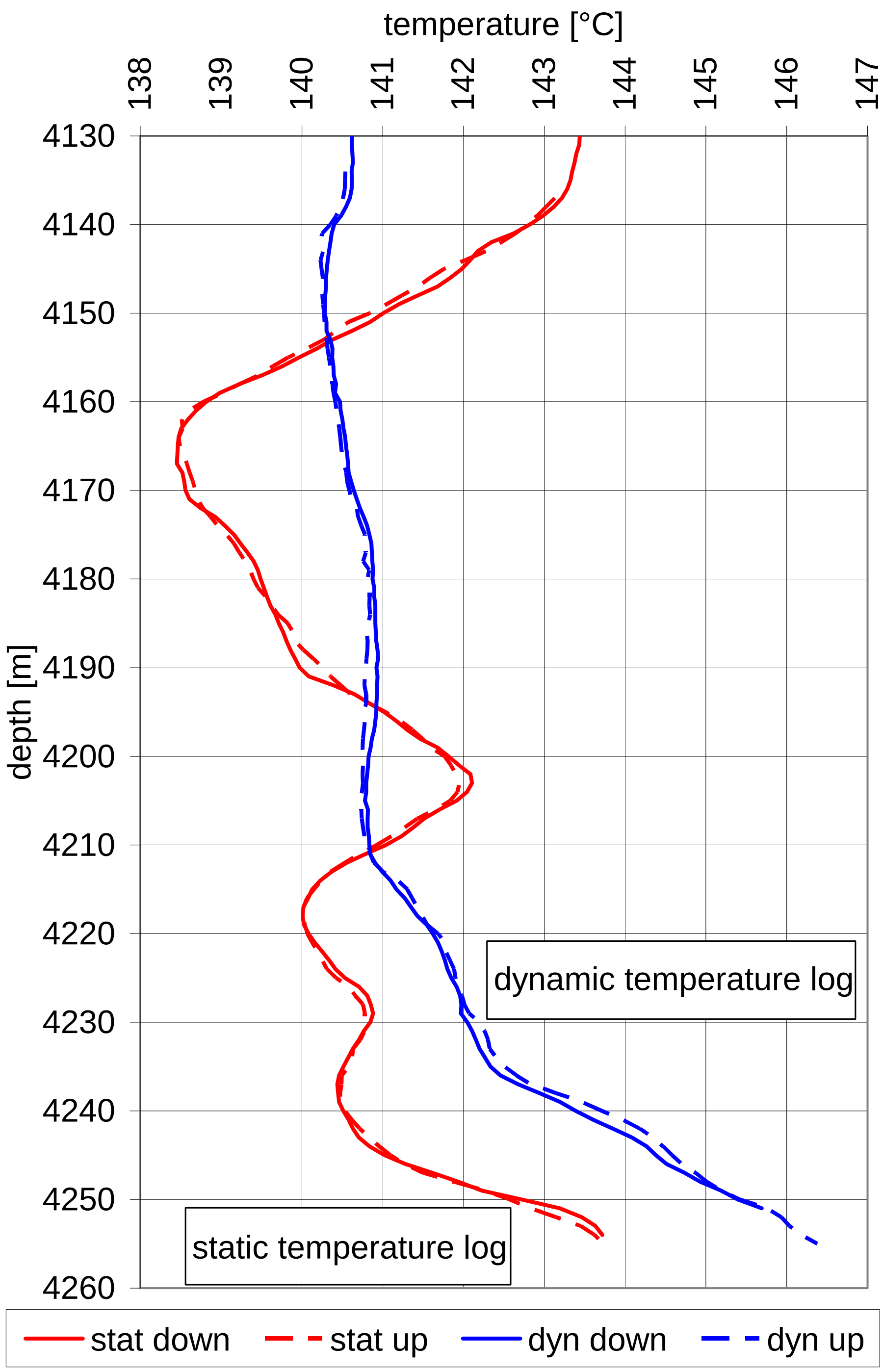
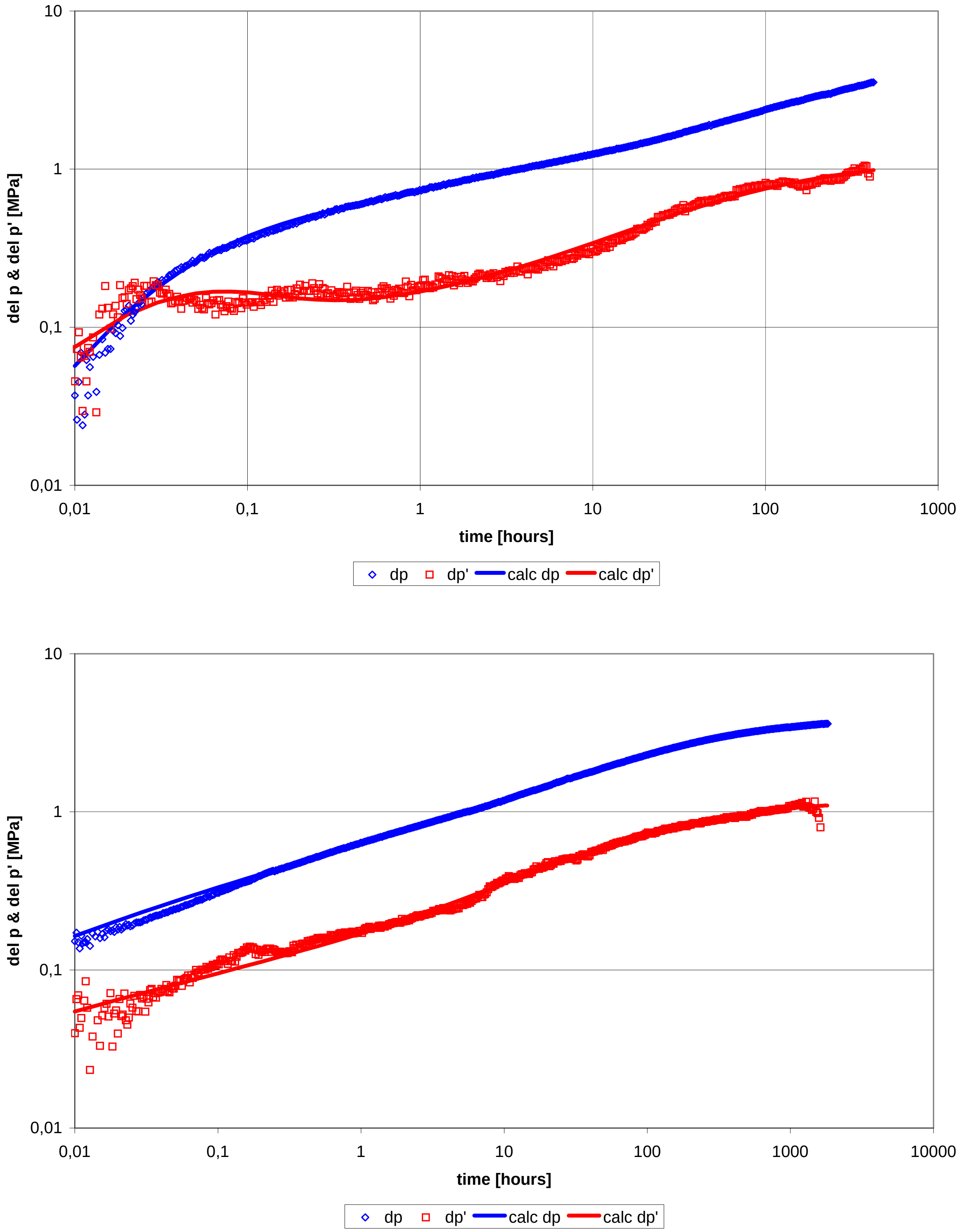


Figure 6: Temperature profiles before (static) and during production (dynamic) in the open section of the well. The temperature changes before production are due to the injection of cold water during the stimulation treatments.



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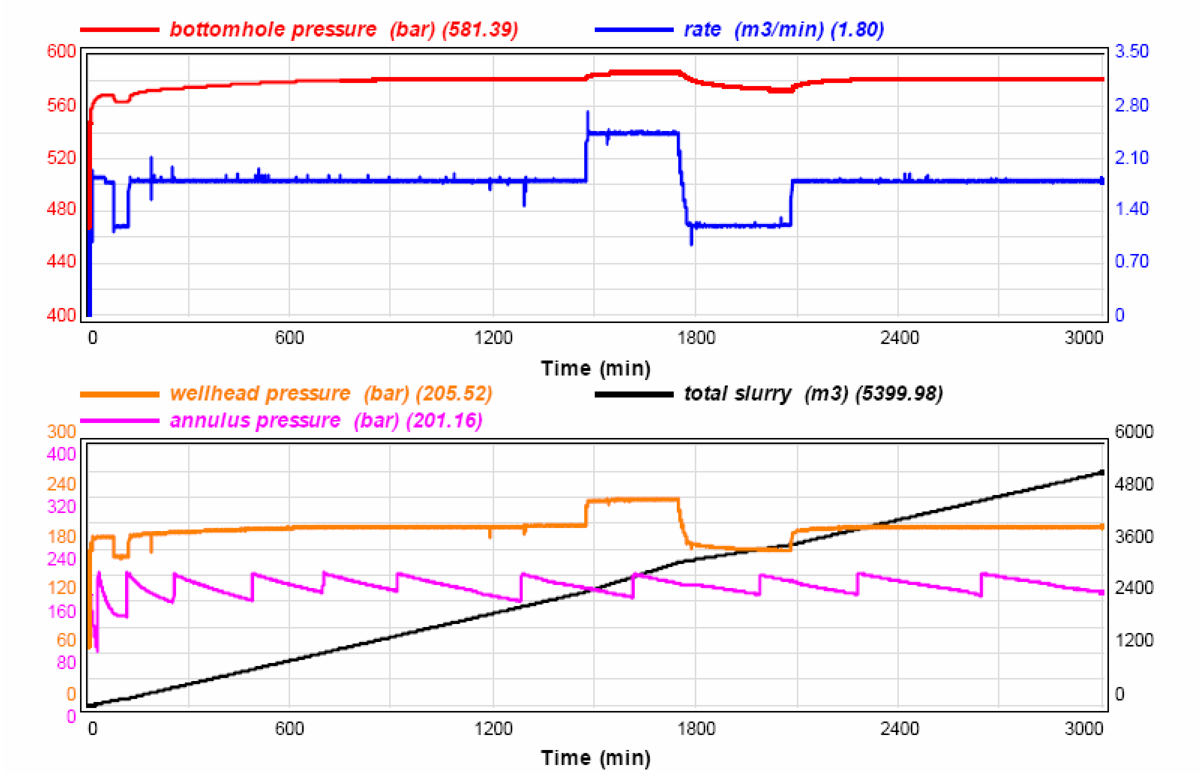

Figure 8: Pressures and flow rates during the waterfrac stimulation

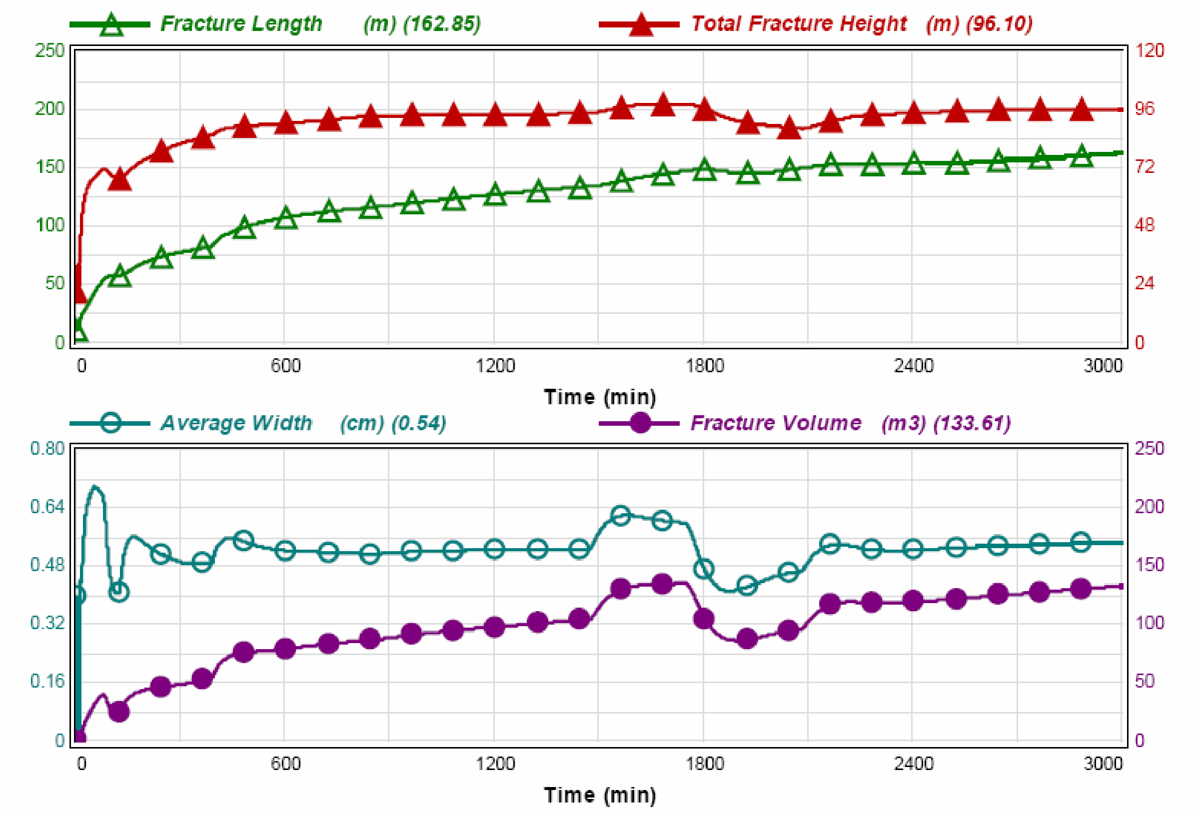

Figure 9: Calculated geometry of generated fracture during the waterfrac stimulation

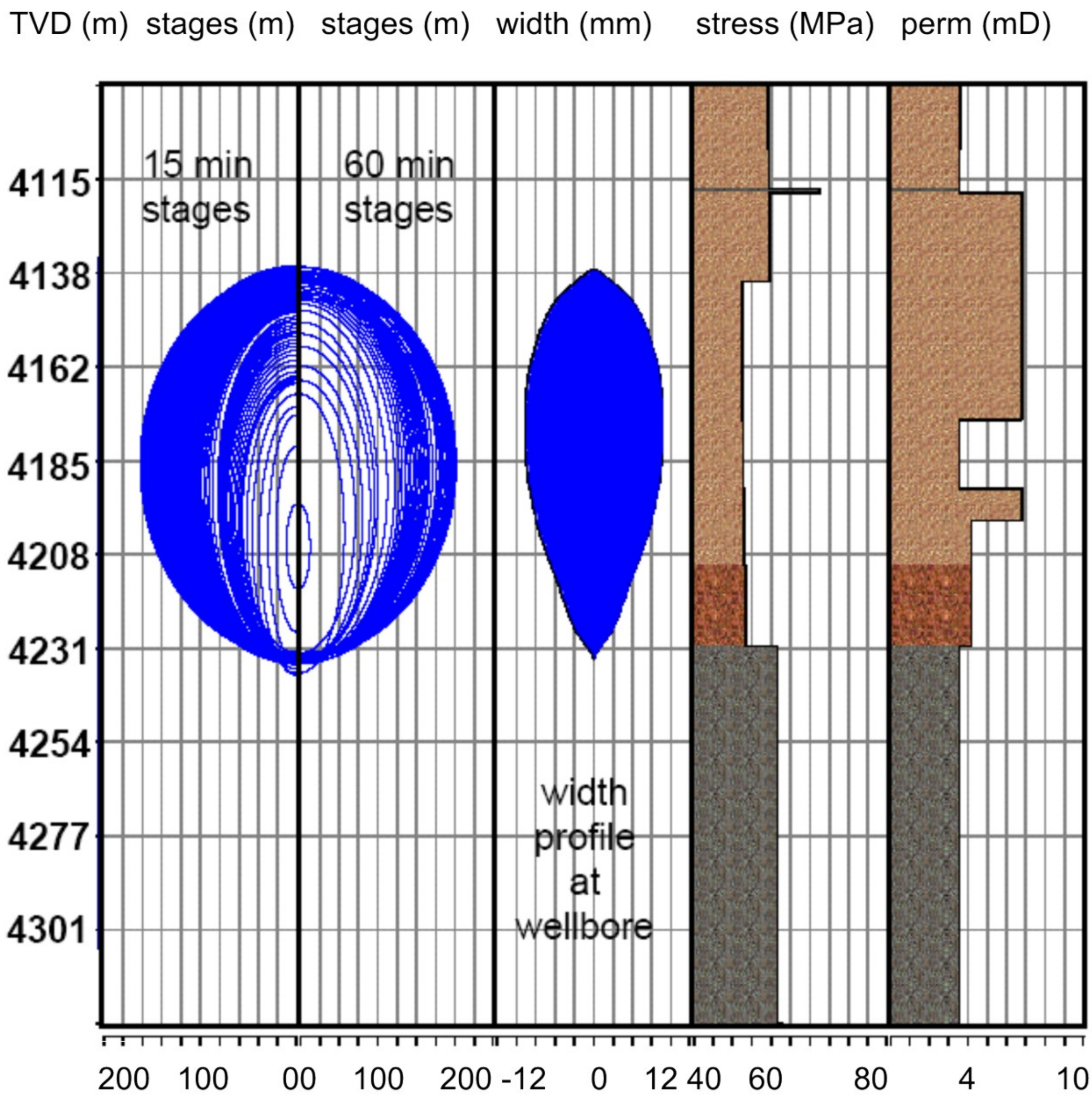

Figure 10: Final geometry of the generated fracture and stress and permeability profile of the waterfrac stimulation

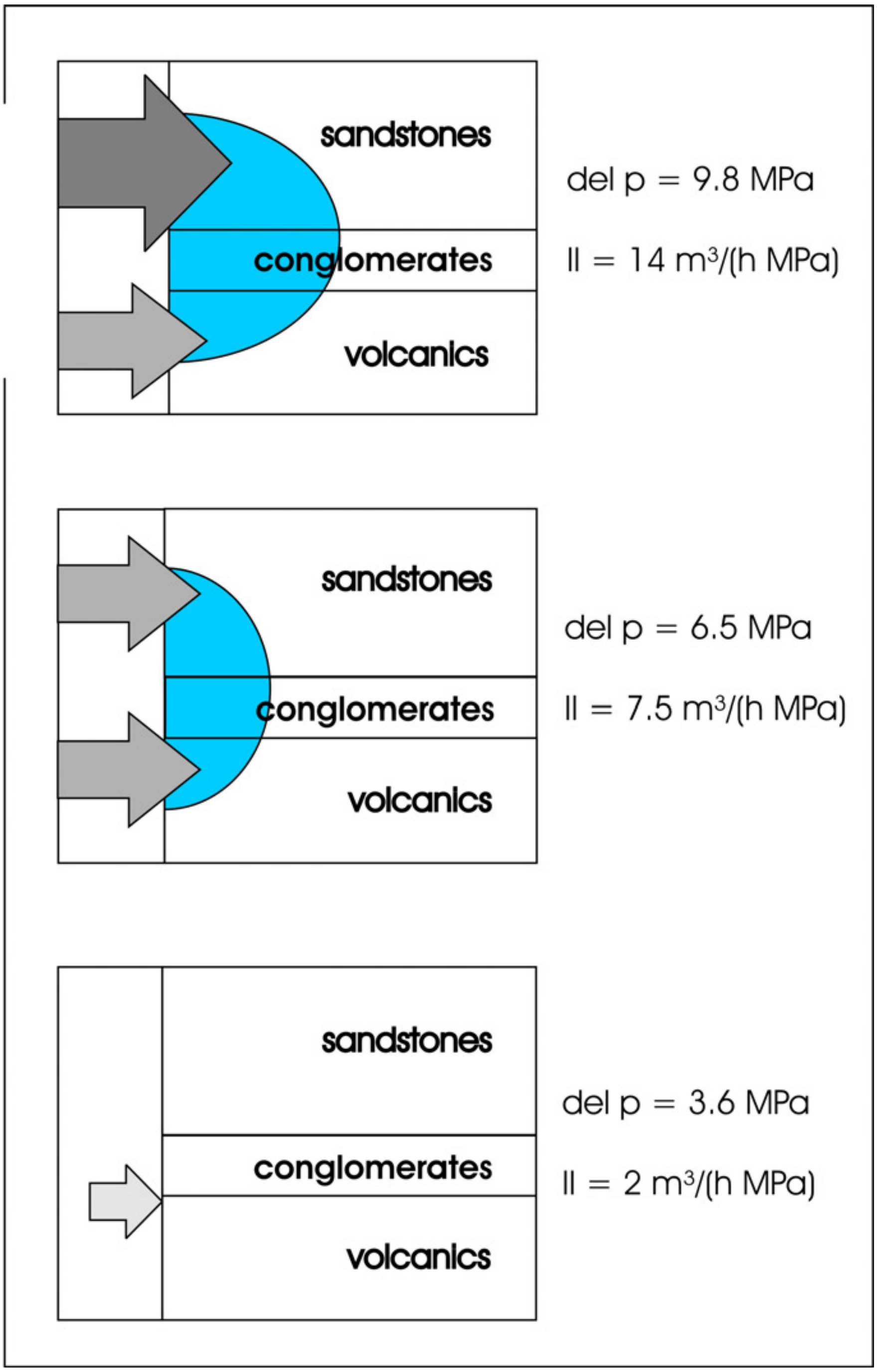

Figure 11: Pressure dependent production efficiency of inflow into the reservoir rock (II = injectivity index). Top: all artificial fractures (from stimulation) are open at reservoir pressure equal to fracture equilibrium pressure. Mid: residual opening of artificial fractures at fracture closure pressure. Bottom: Closure of artificial fractures at low reservoir pressure in the sandstone section; only the fractures in the conglomerates and volcanic rocks remain residually open.

	Duration days	volume m³	flowrate m³/h	diff. pressure MPa	PI/II m³/(h MPa)
casing lift test Jan 2001	0.51	167	13.5	14.0	0.97
casing lift Test Feb 2002	0.58	307	22.4	10.5	2.13
pumping test Aug 2002	37	580	1.0	1.7	0.59
Injection test Jan 2003	8.3	720	3.6	4.3	0.83
flow back test Feb 2003	0.24	338	59.0	14.7	4.03
flow back test Dec 2003	1.0	859	15.6 – 52.8	6.7	7.46
injection test Dec 2004	17.9	3091	7.2	3.5	2.02

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