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MASSIVE HYDRAULIC FRACTURING IN LOW PERMEABLE SEDIMENTARY ROCK IN THE GENESYS PROJECT

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ABSTRACT

Within the GeneSys project in Hanover (Germany) the feasibility of geothermal energy extraction out of low permeable sedimentary rock shall be demonstrated. A geothermal well was drilled down to 3901 m depth. The permeability in the perforated target zone between 3703 and 3709 m is in the range of 10^{-18} m^2. Minifracs and step rate injection tests revealed a high stress level. The minimum principal stress is about 90 % of the overburden.

In 2011 a massive frac operation was successfully performed. About 20,000 m³ of filtered fresh water were injected at flow rates up to 90 l/s. No additives were added to the water. The pressure response during fracturing indicated the creation of a highly conductive fracture.

Different methods were applied to monitor the fracture development. But neither the near surface seismic network, nor remote sensing (GPS-Monitoring and INSAR) provided any signals related to the fracture propagation. On the other hand the comprehensive monitoring demonstrated that under this geological setting massive fracturing does not cause any detectable ground motion.

Two low rate injection tests were carried out after fracturing at a pressure level significantly below the fracture closing pressure. These tests provided the hydraulic evidence for a highly (infinite) conductive fracture and a fracture area in the range of 1 km^2. Despite of the pressure dependant response the fracture retained a highly hydraulic conductivity.

In an artesian production test half a year after fracturing salt saturated water was produced and a salt plug developed in the well.

The origin and the consequences of the high saline water are now serious issues for the project.

INTRODUCTION

The GeneSys project (GeneSys: Generated geothermal energy systems) is an EGS demonstration project for heat extraction out of low permeable sedimentary rock. It is aimed at the geothermal heat supply of the GEOZENTRUM Hanover with a thermal output of 2 MW.

The geology at the location in Hanover is representative for large areas in North Germany. Thus, if the utilisation of these low permeable sedimentary rock can be demonstrated successfully, a new prospective for geothermal energy recovery may be developed in the North German Basin and beyond.

A single well concept has been envisaged for the GeneSys project, mainly for economical reasons. The large expenditures for two deep wells would not be justified for the comparably low thermal output in the range of a few Megawatt.

Before starting the project in Hanover, extended in-situ experiments had been performed at the abandoned gas well “Horstberg” (Kehrer et al., 2007). The good results and the gained experiences in Horstberg provided the basis for the project in Hanover.

In Horstberg massive fracture treatments were performed by injecting pure fresh water at high flow rates (Jung et al., 2005). A large and highly conductive fracture was created in the Detfurth sandstone with pressure dependant properties (Wessling et al. 2009). The large remaining fracture area at a pressure level below the reservoir pressure indicated a significant geothermal potential.

Based on the fracture treatments two different single well schemes had been investigated.

In one scheme water was circulated between two sandstone layers which are connected via an artificial fracture.
The other tested concept was a cyclic one: Cold water was injected into the large fracture and produced back as hot water after a defined residence time (Orzol et al., 2005).
Both concepts had been tested over time periods between days and weeks but not in a long term.
In 2009, the project in Hanover was commenced. The geothermal well “Groß Buchholz Gt1” was drilled down to 3901 m depth (Schäfer et al., 2012) with the target formation Middle Buntsandstein. Similar to Horstberg, only low permeable sandstones were encountered. Thus, an underground heat exchanger had to be created artificially by fracturing.
The paper deals with the relevant pre-frac tests in Hanover in order to predict the fracture propagation and describes the performance of the frac operation itself. Further, a preliminary interpretation of the frac is given based on injection and production tests after fracturing.

WELLBORE AND SITE DESCRIPTION

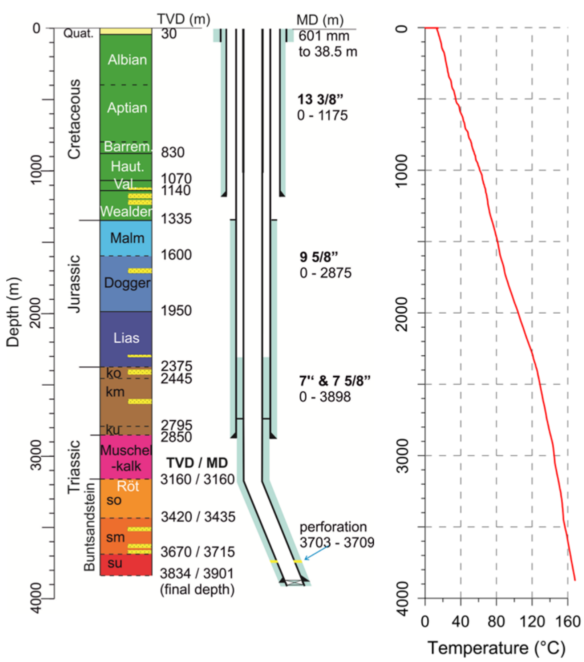

Fig. 1: Geological profile, well completion and undisturbed rock temperature of the GeneSys borehole in Hanover. (TVD: True Vertical Depth; MD: Measured Depth). The mid of perforation is at 3660 m (TVD).

The drilling site is located on the premises of the GEOZENTRUM in the northeastern part of Hanover.
The distance between the drilling platform and the first houses of a nearby housing estate is less than 100 m. Consequently, noise protection is a great issue and a challenge for all operations.
The geological set-up is characterized by a graben structure between two salt stocks at a distance of about 10 km, respectively.
The target zone, Middle Buntsandstein between 3440 m and 3710 m, comprises the Solling-, Volpriehausen- and Detfurth sequences (Schäfer et al., 2012). All three sequences are composed of interlayered beddings of clay, silt, and sandstone.
The cumulative sandstone thickness summarizes to about 10 m within the Detfurth (3527 m – 3568 m) and to about 20 m within the Volpriehausen sequence (3568 m – 3710 m).
Laboratory measurements on core samples confirm a very low permeability of the sandstone layers. Their averaged permeability is between 10^{-16} and 10^{-17} m^2 within the Detfurth sandstone and in the order of 10^{-18} m^2 in the Volpriehausen sandstone (Krug et al., 2013).
As a consequence of the very low permeability of the Buntsandstein a single well circulation scheme as tested in Horstberg cannot be implemented. For that concept a minimum permeability in the order of 10^{-15} m^2 for at least one sandstone layer is required (Krug et al., 2013). Otherwise no sufficient hydraulic connection between the production and injection zone can be reached. But the utilization of the artificial fracture in a cyclic injection and production mode remains still an option for a geothermal utilization.
A surprisingly high rock temperature of 169°C was measured at the final depth in 3901 m (Figure 1). Thus, the averaged geothermal gradient amounts to about 4.2 K/100 m which is significantly higher than the mean gradient in Germany.
The borehole diameter and the well completion are typical for deep drillings in the North German Basin. A 7’’/7 5/8’’ liner/casing provides access to the formation (Figure 1).
Below 3160 m the borehole was inclined towards 30° from the vertical in an azimuthal direction of about N220°. The azimuthal deflection corresponds to the direction of the minimum principal stress (Krug, et al., 2013). Accordingly, fractures will develop perpendicular to the azimuthal well path and multiple fractures may be created in order to enhance the cumulative fracture area.
The well completion allows hydraulic access to permeable sandstones of the Wealden formation between 1175 m and 1325 m via the 13 3/8’’ – 9 5/8’’ annulus. This zone may serve as a reinjection horizon for produced formation water instead of disposing the water at high costs otherwise.

PERFORATION, MINIFRAC AND STEPRATE INJECTION

The access to the formation was created by perforation. However, for the selection of a perforation zone a high rock permeability could not be applied as criterion because of the overall low permeability even in the sandstone layers. Rather a very low permeability could be advantageous. The lower the permeability, the larger fracs can be created since the fluid loss becomes smaller, too.

A deep sandstone layer of the Volpriehausen sequence between 3703 m to 3709 m was selected for perforation. The deep sandstone was selected mainly because of an expected lower stress level compared to adjacent clay or silt horizons. A low stress is advantageous for a frac operation from a technical point of view and seems to favor a high and persisting fracture conductivity. The perforation was performed with big holes and 240 shots at 60° phasing.

The first test for developing the reservoir was a minifrac test. A volume of just 2.5 m^3 of fresh water was injected at a rate of about 1 l/s to pressurize the well and later with only 0.17 l/s (10 l/min) to break the formation. The break down was observed at approximately 370 bar wellhead pressure (Fig. 2). The tiny rate, sufficient for break down, confirmed the assumption of a very low permeable rock.

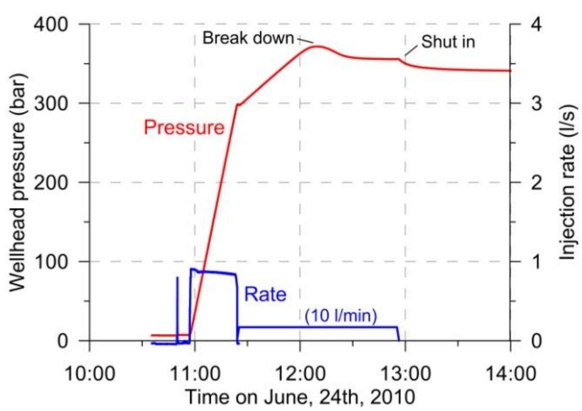

Fig. 2: Pressure curve and flow rate (in liter per second) during the minifrac on June, 24th, 2010. The wellbore was filled with saltwater with a density of 1.12 kg/l (at the mean temperature in the wellbore of appr. 80°C).

From the pressure decline during shut in the fracture closure pressure was determined as measure for the minimum principal stress. At mid of perforation (3705 m MD or 3660 m TVD) a minimum principal stress value of 750±3 bar was derived. Taking into account a normal faulting regime the minimum principal stress is as high as 90% of the maximum vertical stress. Thus, the state of stress seems to be almost isotropic and only little shear tendency can be expected.

During the minifrac the borehole was filled with saltwater with a density of 1.12 kg/l. Hence, the wellhead pressure would be significantly higher if the wellbore was filled with fresh water. A minimum fracture propagation pressure of 410 bar at wellhead can be concluded for a fresh water filled wellbore if the injection rate is small and cooling of the well can be ignored.

The minifrac test was repeated once again with the same injection rate and a similar volume. The pressure response could be reproduced completely.

The second important test before massive fracturing was a step rate injection test (Figure 3). Now a significantly larger amount of 120 m^3 of fresh water was injected at or above the fracturing pressure. The injection rate was increased stepwise from 1 l/s up to 12 l/s and stepwise decreased after injection of little more than one borehole volume. In the subsequent shut in period the wellhead pressure remained almost stable at a high pressure level of about 390 bar for several days. This high and stable pressure level indicates again a very low permeable formation.

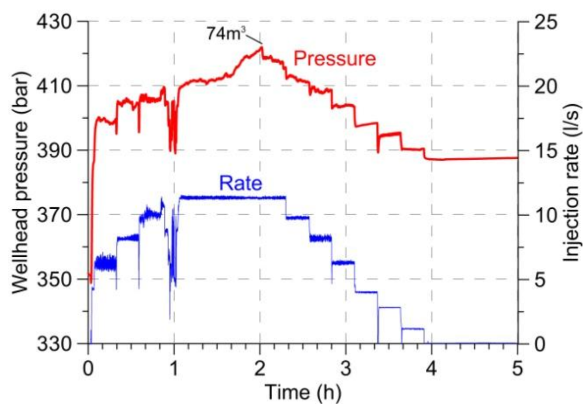

Fig. 3: Pressure curve and flow rate during the step rate injection test on March, 30th, 2011. The pressure peak corresponds to the injection of one borehole volume (74 m^3).

The step rate injection test was investigated with respect to the near wellbore friction. The immediate pressure drop after each rate reduction at the end of the test determines the near wellbore friction. These friction losses summarize to 27 bar at a rate of 10 l/s. In view of a massive frac operation, with a scheduled rate of 80 l/s (see below) the observed near wellbore friction was too high. Accordingly, the decision was made to perforate again.

The second perforation in the same interval was now carried out with deep holes in order to overcome or to reduce the near wellbore restriction. Again 240 shots were shot but with a phasing of 45°.

FRACTURE AREA AND PREDICTION OF FRACTURE PROPAGATION

Because of the low permeability of the encountered rock a significant heat extraction can only be ensured by the creation of a large fracture area. The fracture area serves as heat exchanger with the conductive heat transfer perpendicular to the fracture faces. The necessary dimension for a single fracture plane to extract 2 MW thermal for 25 years is in the range of 0.5 km^2 - if a temperature drop of about 60 K over 25 years may be acceptable. For the framework requirements in Hanover a temperature reduction in the fracture from about 160°C to 100°C within 25 years matches the technical requirements. Then the production temperature remains still above 100°C, the lower limit for the heat supply into the heating system of the GEOZENTRUM.

More detailed considerations and numerical modeling had been performed for the similar conditions at Horstberg (Sulzbacher & Jung, 2010). It could be shown that even a significantly smaller fracture area may be sufficient for the envisaged 2 MW if the water penetration into the rock matrix and the corresponding convective heat transfer is included as well as the conductive heat transfer across the boundaries of the fracture within the fracture plane itself.

On the other hand the hydraulic properties of the created fracture are crucial. Assuming a cyclic operation of the system, cold water will be injected at a pressure level close to the fracturing pressure. Some reopening of the fracture will occur and a hydraulically conductive fracture is fully available for water flow.

Later during the artesian production out of the fracture the pressure level in the fracture will drop and a partial closing seems to occur (Wessling et al., 2009). It is important that a sufficient part of the original fracture remains highly conductive even if the pressure declines significantly below the fracture closing pressure.

The mechanisms why waterfracs in low permeable sedimentary rock can be created successfully is not well understood. Based on the practical experiences made in Horstberg and earlier in Soultz (Tischner et al., 2007) it seems to be necessary to create large fracture areas in the order of 0.1 km^2 or more. Only then highly conductive fractures seem to persist (partly) when the pressure declines during production.

Based on the above arguments the creation of a fracture area of at least 0.5 km^2 was envisaged for the frac operation in Hanover.

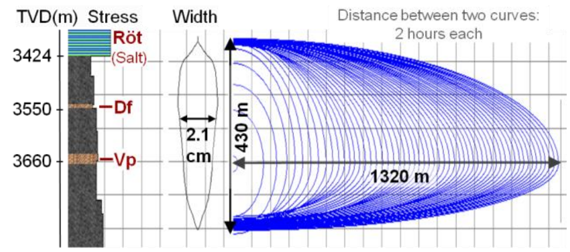

Fig. 4: Scheme of the calculated fracture development for a constant injection rate of 80 l/s and a water volume of 20,000m^3. Left: Vertical profile of the minimum horizontal stress, Mid: Vertical profile of the fracture width at the borehole, Right: Horizontal and vertical evolution of the fracture in 2 hours steps, Df: Detfurth sandstone, Vp: Volpriehausen sandstone. The gray shaded areas in the stress profile represent claystone.

Figure 4 shows a simulation for the evolution of a tensile fracture by applying the software FIELDPRO (Fa. RESNET). Here, the injection of 20,000 m^3 of water at a rate of 80 l/s was assumed.

The relevant rock parameters for the simulation are shown in table 1. The parameters for the sandstones and claystones were derived from core investigations and logging (e.g. sonic log). The parameters for salt reflect averaged values measured on salt samples from different locations. Lithostatic conditions were assumed in the salt layer (Röt) with an averaged density of the overburden of 2400 kg/m^3 as derived from density logs. The stress magnitudes in the other formations were derived on the usual assumption that the overburden in combination with the Poisson ratio determines the horizontal stress (Economides & Nolte, 2000).

*Tab.1: Rock physical parameters for the simulation of the fracture propagation. Dens.: Density, Young: Young's modulus, Pois.: Poisson ratio, Perm.: Permeability, Stress: Minimum horizontal stress. *: The range for the stress in the clay layers is mainly caused by the vertical height variation – see Fig. 4.*

Formation	Dens. (kg/m^3)	Young (GPa)	Pois. ratio	Perm. ($10^{-18}m^2$)	Stress (bar)
Röt (Salt)	2050	33	0.25	0.0001	827
Df-Sandst.	2650	45	0.19	10	730
Vp-Sandst.	2650-2700	65	0.18-0.22	1	750-760
Clay	2700	49	0.23	0.1	720-790*

Additionally a lateral tectonic stress of 80 bar was added in order to fit with the measured minimum principal stress of 750 bar and an artesian pore pressure of 600 bar at perforation depth was assumed similar to the conditions in Horstberg.

Usually the permeability of the surrounding rock essentially controls the fracture evolution. In the current case the permeability is very low in all formations (Table 1). The calculated frac efficiency (relation between water volume in the fracture and the leakoff volume) at the end of the frac operation is therefore as high as 95 %. By far most of the water serves for the fracture propagation and does not leak off within the considered three day operation. Even if the permeability of the sandstone would be higher by one order of magnitude the fracture propagation and frac efficiency would not change significantly because of the still very low permeability.

The vertical extension of the fracture is restricted by the high stress in the salt layer (Röt). However, according to the calculation some penetration into the salt layer will occur.

The calculation results in a fracture half length of 1320 m, a vertical extension at the borehole of 430 m and an averaged width of about 2 cm. Accordingly, the calculated fracture area comprises 1.1 km^2 - more than the aimed target. However, the calculation has to be considered with care because of many uncertainties. Even more important is the fact that no serious prediction is possible to which extend the created fracture remains highly conductive after the frac operation and after pressure release. For those reasons it is better to pump a larger frac than taking the risk of a too small frac operation.

PERFOMANCE OF THE FRAC OPERATION

The frac operation was performed in May 2011 as pure water fracture treatment. The focus of the frac operation was the creation of a large and highly conductive fracture. In the preceding project at Horstberg the massive frac operation was performed as pure water frac under similar conditions. The experiences of Horstberg gave the justification to apply fresh water only. Consequently, no additives were added to the fresh water.

The water was taken from a surface channel ("Mittellandkanal"). Water lines and booster pumps were temporarily installed over a distance of about 1 km from the channel to the drillsite.

At the drillsite the water was filtered through membrane filter presses to remove all organic and inorganic particles (Fig. 5). Subsequently, the filtered water was stored in tanks and from there pumped into the well.

High pressure pumps with an installed hydraulic power of about 8 MW were onsite. All pumps were sound capsulated in order to minimize the sound emissions. A noise protection wall with a height of 10 m was additionally installed around the high pressure pumps. Besides, the frac operation was interrupted during the nights to avoid any disturbance of the nearby residents due to unavoidable low frequency sound emissions.

Fig. 5: Drillsite during the frac operation in May 2011.

The water was directly pumped through the 7" liner of the well without an additional frac string (see Fig. 1). In the annulus between this liner and the outer 9 5/8" casing a pressure of about 100 bar was applied as protection for the partly cemented liner.

The whole frac operation was carried out over 5 days without serious problems. As planned, a total volume of approximately 20,000 m^3 was injected. A somewhat higher rate of about 90 l/s was pumped compared to the schedule (80 l/s) in order to compensate for the interruption at night (Fig. 6).

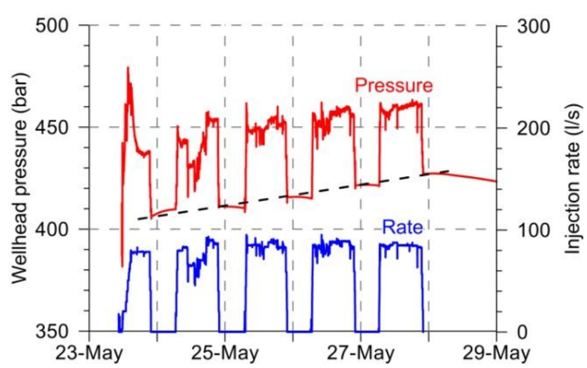

Fig. 6: Wellhead pressure and injection rate during the frac operation in May 2011. The dashed black line illustrates the continuous increase of the instantaneous shut in pressure.

At the beginning of each injection phase the flowrate was increased in several steps and at the end of each phase the rate was stepwise decreased again. A maximum pressure of approximately 480 bar was passed at the beginning of the first day indicating some restriction for the frac propagation or significant friction losses within the fracture. Afterwards the pressure level decreased significantly. During the next days a moderate increase of the pressure level was observed. The instantaneous shut in pressure as measure for the pressure in the fracture increased from 406 bar on the first day to 427 bar at the end of the operation. The observed pressure level fits therefore well to the prediction from the minifracs.

The immediate pressure drop at the end of the individual injection phases reflects the near wellbore pressure loss (Fig. 7). However, from day three on the almost complete pressure drop can be attributed to friction through the liner. The near wellbore friction is small compared to the friction in the liner and indicates a good hydraulic communication between the well and fracture.

Further good indications were the extended pressure oscillations immediately after the stop of pumping (Fig. 7). These oscillations can qualitatively be interpreted with the existence of a highly conductive fracture and a good wellbore-to-fracture communication.

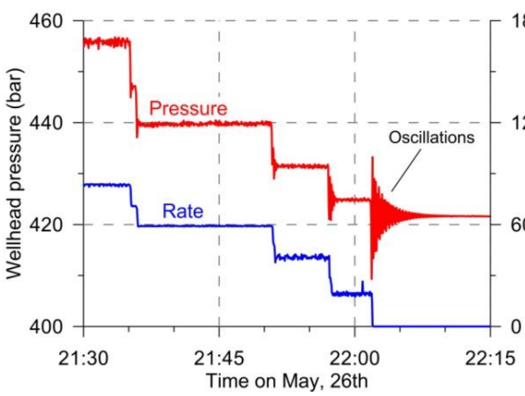

Fig. 7: Wellhead pressure and injection rate during the step down at the end of the 4th day on May, 26th, 2011.

The general trend of an increasing wellhead pressure during the frac operation fits to the assumption of a vertically bounded fracture and a preferred lateral fracture propagation (Gulrajani & Nolte, 2000). A more detailed consideration shows however that the pressure curve cannot be simply matched. In figure 8 the observed net fracture pressure is plotted against the calculated one. (The net fracture pressure is derived by substracting the closure pressure of 750 bar from the observed downhole pressure. The observed downhole pressure was obtained by adding the constant weight of the water column to the wellhead pressure and substracting the friction loss in the wellbore.) In general, the measured net fracture pressure increases stronger than the calculated one. Furthermore the calculated curve predicts almost no friction within the fracture (almost no rate dependency) whereas the measured curve shows some rate dependency. Likely, the predicted frac geometry is an oversimplification of the real one. An idea might be that parts of the fracture – e.g. at the periphery - have a significant smaller width than predicted and thus lead to some friction within the fracture. Further investigations are necessary to match the curves in a better way and to better understand the whole fracturing process.

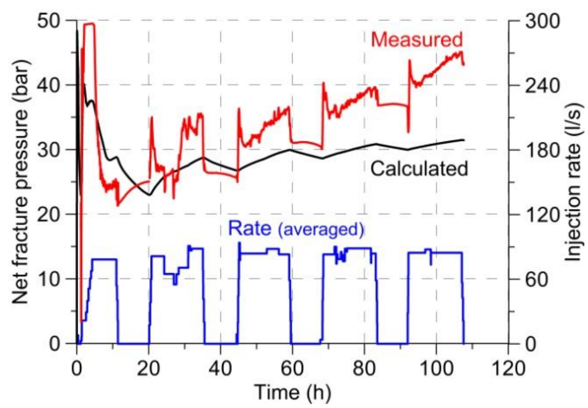

Fig. 8: Comparison of the measured (red) and calculated (blak) net fracture pressure. The "measured" pressure for the shut in periods is not corrected for temperature effects. The comparison is therefore only reliable for the injection periods and the instantaneous shut in pressures.
The calculated pressure was determined for the averaged rates (blue) as shown and the measured pressure peak in the first injection period was truncated.

GEOPHYSICAL MONITORING

Great efforts were taken to monitor the frac propagation with geophysical methods.

A seismic network has been operated since the beginning of the drilling work (Fig. 9). It consists of:

- Four stations in shallow wells and at the surface close to the well
- Four stations in shallow wells on an inner circle at a radial distance of 1 km to the well.
- Four surface stations on an outer circle at a radial distance of 4 km to the well.

Additionally nine surface stations were temporarily installed during the two weeks around the frac operation itself (Fig. 9).
The depth of the observation wells was in the range of 100 to 180 m. In the wells 3-component geophones with a cut off frequency of 4.5 Hz have been installed whereas at the surface 3-component seismometer with 1 Hz cut off frequency have been used. At one surface station close to the borehole a broad band seismometer has been operated.

The functionality of the seismic network could be demonstrated for several events. In particular, the perforation shots could be detected at the closest stations. From a comparison between signal amplitudes derived from synthetic waveforms and measured noise amplitudes at the stations the detection capability was estimated at M_w>-0.5.

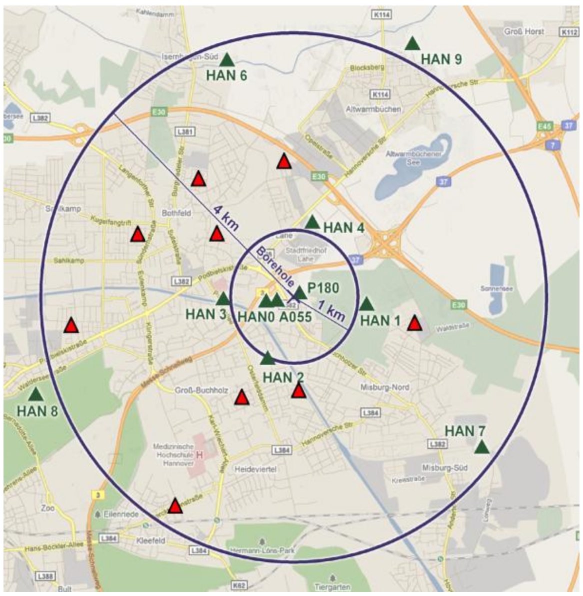

Fig. 9: Map of the seismic stations around the borehole in Hanover. Green triangles: Permanent stations on the inner and outer observation circle; Red triangles: Temporal surface stations.

During the frac operation the real-time analysis was assured by a 24/7 seismological service. The seismic signals were continuously evaluated by experienced seismologists. However no seismic event could be detected. Thus, we can exclude that seismicity with larger magnitudes has been induced by geothermal activities. (Bischoff et al., 2012).

The experiences made in Hanover seem to confirm that seismic monitoring from the near surface is not sensitive enough to detect small induced events in deep sedimentary rock. Deep observation wells are necessary to record those events (Kwiatek et al., 2010). In Hanover and nearby no deep observation well is available.

Besides the seismic monitoring potential deformations at the surface were investigated by applying two methods of satellite remote sensing:

- Differential synthetic aperture radar interferometry (SAR interferometry)
- High resolution GPS monitoring

For the SAR study TerraSAR-X pictures with high resolution were evaluated. The pictures were taken every 11 days between February and June 2011 according to the orbit cycle of the satellite.

For the GPS study carrier wave phase measurements were evaluated. Three GPS stations were temporarily installed at a distance of less than one kilometer to the borehole. Additionally, two permanent GPS reference stations in Hanover were included into this study.

Both satellite remote sensing methods provided no indications for any deformation at the surface.

Thus, it has to be concluded that none of the applied methods gave information on the frac propagation. However, the very positive aspect is that no detectable ground motion and no disturbance at the surface were induced.

POSTFRAC INJECTION AND PRODUCTION TESTS

It was originally intended to monitor the pressure decline after the frac operation for about 2 weeks and then to start the artesian production for clean up and testing the well. New regulations for handling the backflow led to a shift of the back-production for about 5 months.

Figure 10 shows the undisturbed pressure decay between May and November 2011.

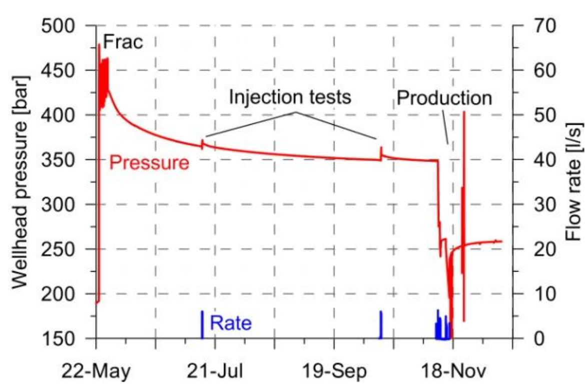

Fig. 10: Wellhead pressure decline after the frac operation. The hydraulic tests between May and December 2011 are marked. The flow rate is given as positive number for injection as well as for production and is not shown for the frac operation in May 2011.

The pressure declines from about 420 to 340 bar within 6 months indicating fluid loss into the matrix. Obviously, the water flow via the created large fracture area into the low permeable matrix is not negligible anymore. The pressure stabilizes at about 340 bar wellhead pressure with a borehole that is filled with fresh water. This pressure level was reached later again after production tests and seems to reflect the undisturbed reservoir pressure. Therefore, it must be concluded that the reservoir is highly pressurised, similar to the reservoir at Horstberg (Wessling et al., 2009). The observed high pressure level during the fracture treatment is in fact low compared to the reservoir pore pressure.

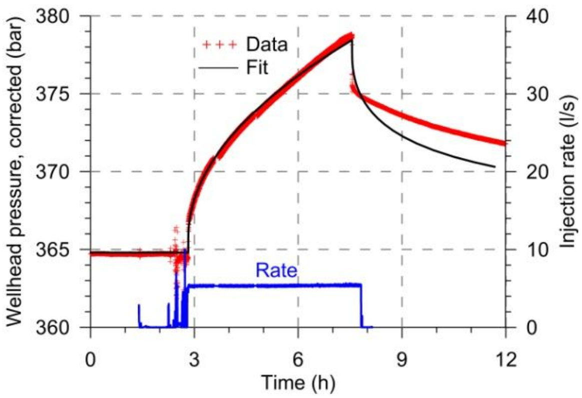

Fig. 11: Wellhead pressure and fitted wellhead pressure for the short term injection test on July 14th, 2011. The wellhead pressure was corrected for temperature effects in the well and thus reflects the pressure change downhole.

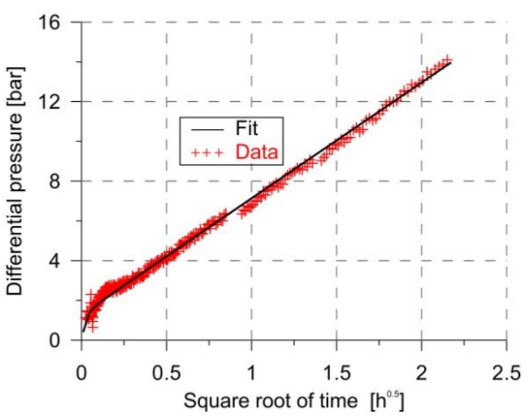

Fig. 12: Corrected wellhead pressure (data and fit) as in Fig. 11, plotted as differential pressure versus the square root of time for the injection phase.

On July 14th and October 12th, 2011 two identical short term injection tests were performed in order to investigate the properties of the fracture at different pressure levels below the closure pressure (Fig. 11). Compared to the flow rate during the frac operation only low rates were applied. In both tests 90 m^3 of water were injected at a rate of 5 l/s.

The injection tests lead to a moderate pressure rise of about 15 and 20 bar, respectively. The observed pressure response approved qualitatively the existence of a permeable fracture. Otherwise the pressure would have increased above the fracturing pressure again.

A more detailed examination reveals a pressure increase proportional to the square root of time, clearly indicating a linear flow regime (Fig 12). Very likely the pressure response is controlled by linear flow perpendicular to the fracture faces into the matrix, the so called formation linear flow (Gringarten et al., 1974). Accordingly, a large and highly (infinite) conductive fracture has been approved hydraulically. From the pressure curve fitting (Fig. 11) the effective fracture area can be derived under the assumption of a given matrix permeability. The evaluation of the first injection test on July 14th yielded the following fracture area A for estimations of the vertically averaged matrix permeability k_{av}:

$A = 0.4\ km^2$ for $k_{av} \approx 10^{-17}\ m^2$ or:

$A = 1.3\ km^2$ for $k_{av} \approx 10^{-18}\ m^2$

Hence, a highly conductive fracture area in the order of 1 km^2 may be concluded from the injection test. On the other hand the pressure match (Fig. 11) shows that a simultaneous match of both, the injection and the subsequent shut in phase could not be reached. This discrepancy is likely caused by a pressure dependency of the hydraulic parameters.

The second injection test in October 2011 revealed a formation linear flow, too. However, the derived effective fracture area is now smaller than in the first test but it is still large (> 0.3 km^2). The apparent reduction of the fracture area reflects obviously the pressure dependant characteristics of the hydraulic properties. (A more detailed evaluation of both injection tests is under preparation for publication.)

On November 11th, that means approximately half a year after the frac operation, a production test was started. The artesian produced water was reinjected in a closed loop into the annulus of the well (Fig. 13).

The annulus is in hydraulic contact to permeable sandstone layers of the Wealden formation (Hübner et al., 2012).

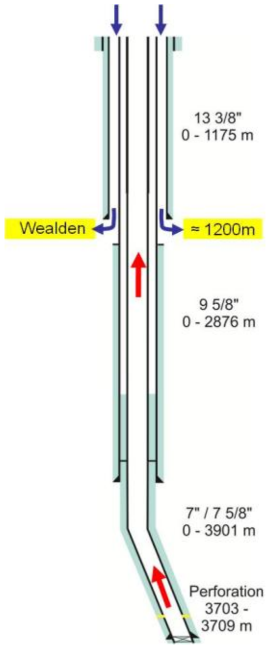

Fig. 13: Scheme of the simultaneous production out of the Buntsandstone and reinjection into the Wealden sandstone via the annulus between the 13 3/8" and 9 5/8" casings.

No pump was necessary for the test. The overpressure in the reservoir was still high enough to facilitate both, production and reinjection without pumping. The production rate was throttled by a choke in order to not exceed a defined pressure limit for the injection horizon.

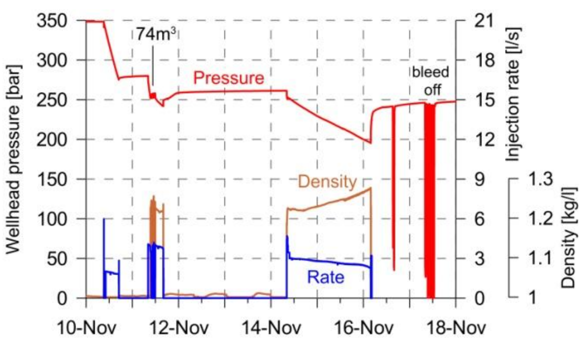

Fig. 14: Wellhead pressure, injection rate and density of the produced water during the production test in November 2011. The density was simultaneously measured with the injection rate deploying a coriolis type flowmeter. The point at which one borehole volume was exchanged is marked (74m^3).

On average it was produced at a rate of 3 l/s (Fig. 14).

The very fact of an artesian production without a drastic pressure drop qualitatively confirms that a conductive fracture exists and that a significant water production out of the low permeable rock is now possible.

At the beginning of production the pressure decline can almost completely be attributed to the exchange of fresh water in the well by high saline formation water. After the production of one borehole volume the density of the formation water increased rapidly above 1.2 kg/l accompanied by a smother pressure decline. Salt scales developed at the measurement devices and in the filter station.

After an interruption on the weekend (November 12th and 13rd) the production was resumed again. Pressure and flow rate declined moderately but the salinity arised continuously up to 1.27 kg/l. The water was salt saturated and at low temperature even oversaturated. Obviously salt crystals developed while producing leading to the high density of the water. After stopping the production for flushing the annulus with fresh water the production could not be started again. A plug has formed in the well acting as a hydraulic restriction. A few days later a slickline measurement approved a salt plug below about 650 m depth. The salt plug consisted of NaCl to more than 95%.

Because of the unexpected problems with saturated salt water and with the plug the whole project was stopped in order to investigate the origin and the extent of the salt occurrence.

Only one year later, in November 2012, the salt plug was removed by applying a capillary coil unit. The salt plug was detected and removed between 650 m and 1300 m. Below about 1300 m no further restriction occurred.

Now, further hydraulic tests shall show if the salt problem may be minimized by flushing the rock, because in samples of the surrounding rock close to the perforation Halite (NaCl) could be detected in traces, only. If this indication is correct, an option exists to overcome the salt problem by some cyclic injections of fresh water and the immediate back-production and disposal of the produced saline water.

In any case the salt problem has already caused a significant delay and means a severe risk for the success of the whole project.

SUMMARY AND CONCLUSIONS

The target formation of the GeneSys borehole in Hanover is the Middle Buntsandstein. Here only very low permeable rock formations occur. Hence a subsurface heat exchanger has to be created artificially by fracturing.

A sandstone interval between 3703 and 3709 m was selected for perforation. The sandstone is almost completely cemented and its permeability is in the order of 10^{-18} m^2. Two minifracs were performed and revealed a high minimum stress magnitude of about 750 bar at perforation. The minimum principal stress is about 90 % of the overburden.

In May 2011 a massive waterfrac was carried out. The aim of the frac operation was the creation of a large fracture area of more than 0.5 km^2. Water lines and booster pumps were temporarily installed in order to ensure the water supply at high rates. No additives were added to the water. It was only filtered to remove all inorganic and organic particles. Great efforts were taken to minimize the sound emissions and to protect the nearby residents from noise.

About 20,000 m^3 of fresh water were injected at a flow rate of about 90 l/s. The whole frac operation was carried out over 5 days without serious problems. The measured pressure curve revealed good indications for a highly conductive fracture and for negligible near wellbore friction losses.

Different geophysical methods were applied to monitor the fracture development. But neither the surface seismic network, nor remote sensing (GPS-Monitoring and INSAR) provided any signals related to the fracture propagation.

Based on the experiences and the precautions made in Hanover it is reasonable to perform massive frac operations in an urban area. On the other hand the comprehensive monitoring demonstrated that under this geological setting it is currently impossible to monitor the frac propagation from shallow depth.

Low rate injection tests were performed two and five months after fracturing, respectively. These tests provided evidence for a highly (infinite) conductive fracture and a fracture area in the range of up to 1 km^2. It has to be emphasized that these tests were carried out at a pressure level significantly below the closure pressure of the fracture. Thus, the fracture retained a high hydraulic conductivity even though no proppants were used to keep the fracture conductive.

In November 2011, with a delay of six months, the artesian back flow of the well was commenced. The pressure response qualitatively confirms that now a conductive fracture exists and that a significant water production out of the low permeable rock is possible.

However, the recovered water was oversaturated with NaCl at surface conditions. A salt plug had formed in the well likely due to cold fresh water injection in the surrounding annulus.

One year later, in November 2012, the salt plug between 650 m and 1300 m was removed by applying a capillary coil unit.

Now further hydraulic tests shall show if the salt problem may be minimized by flushing the rock because only traces of Halite were detected in the surrounding rock. The origin and the consequences of the high saline water are serious issues for the whole project in Hanover and will be addressed further.

However, preliminary investigations indicate that the production of salt saturated water is a local problem in Hanover and occurs only in the Buntsandstein. Temporarily plugging with salt has been reported from a few gas wells producing out of the Buntsandstein, whereas salt plugging is unknown for other deep formations in the North German Basin. Moreover, the experiences made at the test site in Horstberg confirm that the Buntsandstein is not a "critical" formation in general. In Horstberg salt saturated formation water has never been produced.

For the recovery of low permeable rock the hydraulic experiences made in Hanover are very important. These results confirm that the concept of massive water fracturing has a potential for developing low permeable sedimentary rock. Large and highly conductive fractures can be created by water fracturing. This simple concept was now successfully applied at different places and under different geological and geomechanical conditions (Soultz, Horstberg, Hanover,…). The concept seems to be transferable in general to low permeable rock despite the fact that some aspects concerning the mechanism of keeping the fracture conductive are not yet understood.

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