Available online at www.sciencedirect.com
SCIENCE DIRECT
ELSEVIER
International Journal of Rock Mechanics & Mining Sciences 42 (2005) 1028–1041
International Journal of Rock Mechanics and Mining Sciences
www.elsevier.com/locate/ijrmms

Hydraulic fracturing in a sedimentary geothermal reservoir: Results and implications

B. Legarth*, E. Huenges, G. Zimmermann

GeoForschungsZentrum Potsdam, Telegrafenberg, Potsdam D-14473, Germany

Accepted 3 May 2005
Available online 28 June 2005

Abstract

Field experiments in a geothermal research well were conducted to enhance the inflow performance of a clastic sedimentary reservoir section. Due to depths exceeding 4050 m, bottom hole temperatures exceeding 140 °C, and open hole section (dual zone), technically demanding and somewhat unprecedented conditions had to be managed. The fracturing operations were successful. Fractures were created in two isolated borehole intervals and the inflow behaviour of the reservoir was decisively enhanced. The effective pressures applied for fracture initiation and propagation were only slightly above in situ pore pressures. Nevertheless, the stimulation ratio predicted by fracture performance modelling could not be achieved. Multiple reasons could be identified that account for the mismatch. An insufficient fracture tie-back, as well as chemical and mechanical processes during closure, led to reduced fracture conductivities and therefore diminished productivity. The insights gained are the basis for further fracture design concepts at the given and geologic comparable sites.

Keywords: Geothermal; Sedimentary reservoir rocks; Rock mechanics; Hydraulic proppant fracturing; Inflow enhancement; Productivity; Open hole treatment; Fracture modelling

1. Introduction

For geothermal power generation in the North German Basin reservoirs have to be developed that are fluid bearing and show reservoir temperatures of at least 120 °C. Consequently, because of an average prevailing geothermal gradient of 30 °C/km in the basin wells with a depth of more than 4 km are of interest. The reservoirs are low-enthalpy hydrothermal systems making high fluid production rates of more than 20 kg/s necessary for their economic exploitation [1]. Nevertheless, they are of high interest for a large-scale development because of their wide distribution throughout the basin (Fig. 1). In the investigated geological setting potential pay zones of primary concern are therefore Rotliegend sandstones [2]. Zones with sufficient permeability are known within these formations from intensive hydrocarbon exploration and exploitation. However, it has never been tried to explore Rotliegend formations for geothermal heat or power production.

Therefore, a research project was initiated and a series of field experiments were conducted. The objectives of the experiments were:

(1) verification of technical feasibility of multizonal open hole fracturing technology,
(2) creation of highly conductive flow paths to enhance inflow performance,
(3) connection of productive reservoir zones to the well, and
(4) decisive enhancement of overall reservoir productivity.

Although technologically strongly related, there are several main differences looking at exploitation

*Corresponding author. Tel.: +49 331 288 1836; fax: +49 331 288 1450.
E-mail address: bjoern.legarth@gfz-potsdam.de (B. Legarth).

1365-1609/$ - see front matter
doi:10.1016/j.ijrmms.2005.05.014

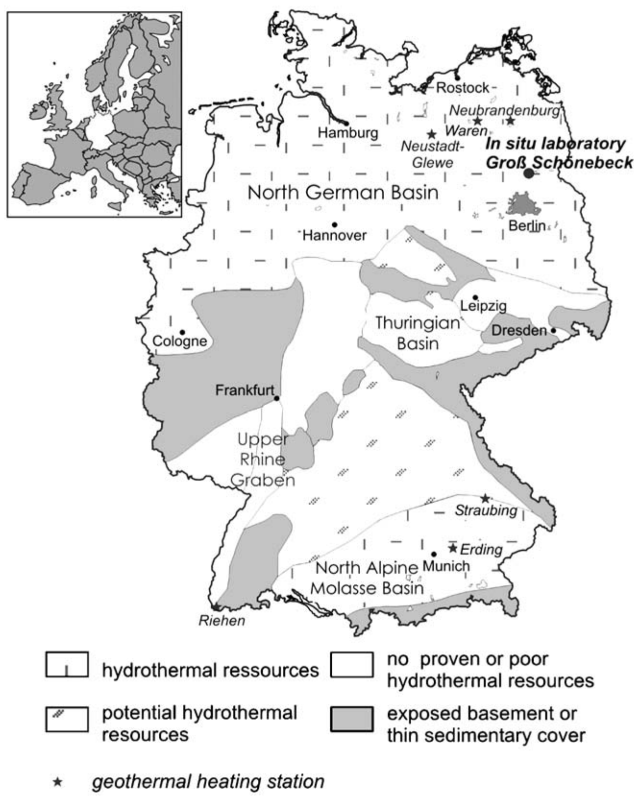

Fig. 1. Location of the ''in situ laboratory Groß Schönebeck'' in the remediated Rotliegend gas exploratory well E GrSk 3/90 [2].

strategies for low-enthalpy geothermal and hydrocarbon reservoirs:

(1) High mass flow rates are required to achieve an acceptable energy efficiency when converting thermal energy stored in produced fluids into electricity by e.g. using binary cycles: 25 m^3 of low-enthalpy geothermal fluid bear same energy content as 1 m^3 of crude oil.
(2) A maximum inflow area has to be connected to the wellbore in order to achieve an efficient fluid production at high mass flow rates. The system efficiency is driven by the energy consumption for the artificial fluid lifting process, which is a function of reservoir productivity, pump efficiency and static fluid level in the well.
(3) Stimulation treatment design has to aim at covering and creating as much net reservoir height (pay-zone) as possible. For hydraulic fracturing operations this means, unless required by other technical reasons, no general need for fracture height (h_f) containment. The hydraulic connection of additional pay zones is an explicit goal of any stimulation treatment. Nevertheless, a minimum initial productivity is required that gets enhanced by reservoir adapted stimulation treatments.

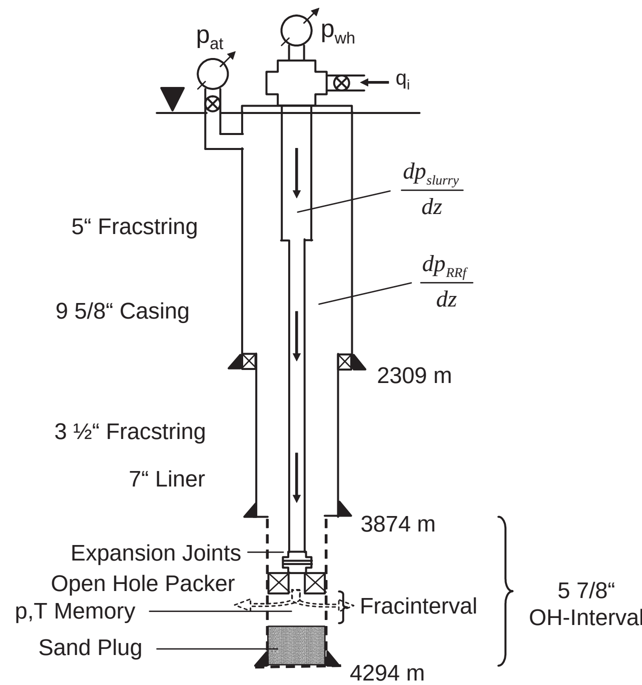

Fig. 2. Schematic of fracturing treatment set-up in the well E GrSk 3/90 [3]; with p_{at}—atmospheric pressure, p_{wh}—wellhead pressure, q_i—injection rate, dp_{slurry}/dz—pressure gradient in fracturing string, dp_{RRf}/dz—pressure gradient in annulus.

The research well (E GrSk 3/90, Fig. 1) used for these experiments is situated near Groß Schönebeck[1] (Germany) and drilled through a sequence of Rotliegend sediments consisting of silt-, sandstones and conglomerate (upper Rotliegend) into the lower Rotliegend comprised of volcanic rocks (Mg-andesites, pyroclastites with interlayered sediments). Initial productivity was significantly lower than it was expected from core measurements. Mainly inflow restrictions (near-well bore damage) limited fluid production. For this reason, multiple hydraulic proppant fracturing experiments have been conducted in the open hole interval. An open-hole packer at top and a sand plug at the bottom of each interval were used as hydraulic barriers (Fig. 2). Applying this configuration, the intervals were fracture-treated placing about 11 ton of proppant (ceramic grains) and over 200 m^3 of fracturing fluid (highly viscous gel) into the formation. The fracture treatments where conducted with two subsequent operations in each interval: a diagnostic treatment (datafrac)—to determine relevant in situ hydro-mechanical reservoir and fracture parameters—and the main treatment (mainfrac) with proppant stages. The focus of this paper is to evaluate and interpret stimulations results. A comprehensive description of experimental procedures can be found in Legarth [3] and the technical report

[1]Gauß-Krüger coordinates: RW 5406044.6 HW 5864387.2 height over NN: +65.98 m.

edited by Huenges and Wolfgramm [4]. The majority of technical terms used in this article originates from petroleum engineering disciplines. The authors kindly recommend Bradley et al. [5] in case additional explanations of general terms and topics are requested.

2. Hydraulic fracturing experience in geothermal reservoirs

So far stimulation of geothermal wells concentrated on acid treatments in carbonates (e.g. Tuscany, Italy) and large scale water-fracturing treatments (e.g. Upper Rhine Graben, France) focused on high-enthalpy mainly crystalline reservoirs. Application of hydraulic proppant fracturing (HPF) to enhance the inflow performance of geothermal sedimentary reservoir rocks (porous-permeable matrix) has not yet been considered on a commercial basis. However, research results on the latter technology exist from the Geothermal Reservoir Well Stimulation Program (GRWSP) from 1979 to 1984 in USA [6–8]. The research program led to three main conclusions relevant for the research work presented in this context: (1) HPF treatments can be successfully applied in sedimentary formations, but requiring a well with initial modest flow rate, (2) open hole completions should be used in order to maximize potential inflow area and mitigate further formation damage, (3) a suitable retrievable open hole packer should be used for zone selective stimulation treatments. The use of the latter was recommended but had not yet been tested.

On the other hand, hydraulic proppant fracturing is a standard technology in hydrocarbon industry and has been commercially applied so far to stimulate oil and gas wells since over 30 years. In 2001, more than 60% of oil wells and more than 85% of gas wells are completed with fracture treatments [9]. Since the 1950s, the term water-fracturing in hydrocarbon industry stands for an application that uses a low-viscosity fracturing fluid with a low concentration of proppants added in order to create long fractures as primary fluid conduits in very low permeable, dry gas reservoirs connecting productive reservoir zones aloof from the wellbore [10]. Proppants are added in order to guarantee a fracture tie-back to the well under drawdown conditions.

Coventional HPF treatments use high-viscosity fracturing fluids (polymer based gels) and large amounts of proppants to create highly conductive flow paths in a porous, permeable rock matrix which, depending on the permeability contrast created, enhance the radial inflow behaviour of the well [11]. Rheology and chemistry of fracturing fluid and the type and properties of proppant are adapted to the treated formation. Thus, a wide range of formations—in terms of permeability—can be treated using this technology [12]. Usually, zonal isolation is achieved by running treatments in cased and perforated intervals with packers or plugs as static or temporary barrier systems.

The experiments presented here investigate the feasibility of multizonal open hole HPF treatments for the stimulation of geothermal wells.

3. Field experiments

The primary goal of the field experiments at the site is geothermal technology development with focus on stimulation concepts.

Open hole completion (3874–4294 m true vertical depth) guarantees a maximum inflow area that would allow a commingled production from all potentially productive reservoir zones in order to achieve a high productivity level. Furthermore, a continuous, undisturbed—by the presence of a casing—monitoring and borehole logging before, during and after the treatments was possible due to direct contact to the reservoir rock.

Stimulation experiments were focused on Rotliegend sandstones for which core measurements indicated permeability values up to 200 mD. For geothermal means this is considered low permeable. Two intervals were selected for stimulation as potential pay zones: 4130–4190 and 4078–4118 m, respectively.

Matrix treatments were ruled out because of two reasons:

(1) the zones showed impaired inflow behaviour prior to stimulation probably due to formation damage as consequence of drilling operations, and therefore a damaged zone had to be effectively bypassed,
(2) pay zones are represented by clastic sediments without carbonate cements; an acidizing job would have at best restored natural porosity and permeability but not created new flow paths that were needed to enhance inflow performance decisively. Even the application of hydrofluoric acids (mud acids) was not an option regarding the risk of destabilizing the well bore due to matrix disintegration as well as environmental and economic issues.

The stimulation concept involved the application of a retrievable hydraulic barrier system to independently and successively treat two intervals in the open hole section of the well (Fig. 2). The annulus between fracturing string and casing was filled with saline fluid and remained open to atmosphere. During the treatments, the fluid level (annulus pressure) was monitored at the wellhead and stayed constant. In each interval a diagnostic treatment (datafrac) was conducted prior to the mainfrac with proppants. The datafrac was designed as a step-rate pure fluid treatment with downhole p,T-recording. Volume and type (linear, low-pH gel) of the

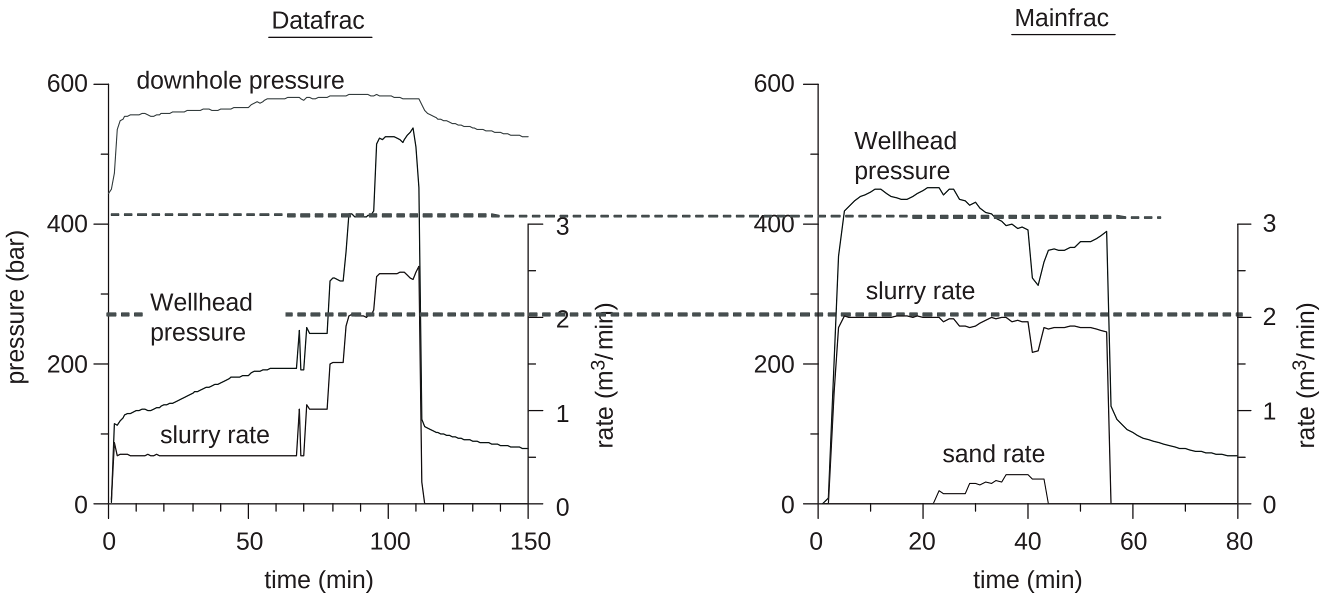

Fig. 3. Pressure and rates for the fracturing treatment in the interval 4130–4190 m. Determination of maximum wellhead pressure and slurry rates (frictional losses) for the mainfrac treatment by applying a step-rate test (datafrac).

fluid system were the same for both experiments. The term 'linear' in this context describes the fluid's viscoelastic behaviour: viscosity increases linearly with polymer concentration. From results of the datafrac the main hydraulic (leak-off coefficient/permeability) and rock mechanical (fracture closure pressure) parameters could be determined, including minimum hydraulic height and volume of the created fracture by pressure-, temperature-logging and history matching pressure responses. The diagnostic measures are necessary for an adequate mainfrac design and secure job executions [13] (Fig. 3).

High temperature and open hole conditions pose a high risk for packer operations in general. Especially fracture height growth had to be limited in order to avoid a by-pass of the packer with proppant-laden fluids that would lead to a screen-out in the annulus.

The lack of experience with this situation made a less aggressive fracture design necessary. This means smaller volumes, lower proppant concentrations and lower pumping rates than required for an optimum treatment. This was identified by pre-treatment fracture modelling. Therefore, treatment pressures and consequently achievable dynamic and final fracture dimensions were limited from the start. The packer consisted of two metal anchor sections preventing vertical movement of the element under loading conditions in both directions. A short rubber element served as hydraulic seal of the annulus between fracturing string and borehole wall. The type of the chosen elastomer as well as the geometry of the sealing section allowed the application in high-temperature environment. To account for axial movement of the fracturing string during the treatment, three expansion joints each 1.5 m long were installed above the packer element. Additionally, the whole fracturing string was fed off by about 40 metric tonnes. The annulus stayed open to atmosphere to monitor tightness of the packer and to avoid fluid loss and/or fracture the formation above the packer seat.

4. Results and discussions

4.1. Mechanical rock response

Fracture closure pressures (p_c) in the two intervals were determined by analysing the pressure decline curve of the datafracs. The term "closure pressure" is defined as the pressure equal to and counteracting the minimum principal rock stress normal to the fracture planes. Together with the permeability profile it is the single most important parameter in order to design and model hydraulic fracturing treatments. The p_c will always be equal to or less than the breakdown pressure (fracture initiation) and always less than the fracture extension pressure. An upper bound of p_c is the instantaneous shut-in pressure (ISIP). With progressing shut-in time, the pressure decline approaches a linear relation with the square root of time. Fracture closure is identified as inflection point on the decline curve where the slope changes. Different time functions are used to scale and analyse treatment pressures depending on the type of fracturing fluid used. Most commonly, the G-function [14] is applied. The latter is derived based on the mass balance and fluid leak-off from the fracture, under the ideal assumption of fixed fracture surface area [15]. A

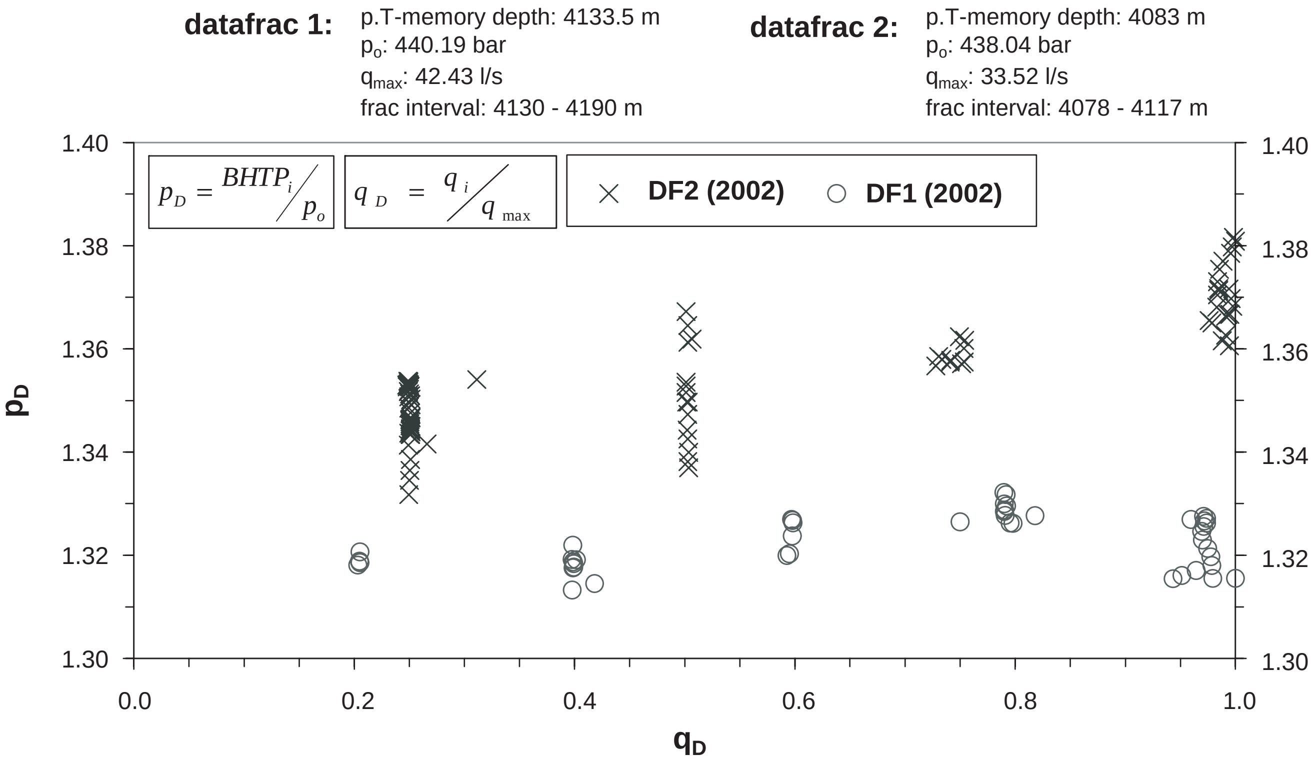

Fig. 4. Downhole pressure vs. rate plot of both datafrac (DF) treatments. The crossplot with dimensionless variables allows a direct comparison of in situ pressure conditions during the treatment. Upshifting of treatment pressures in the second interval can be explained by diverse stress and tortuosity conditions; with p_o—equilibrium downhole pressure before treatment, q_{max}—maximum injection rate during treatment, p_D—dimensionless pressure, q_D—dimensionless injection rate, BHTP$_i$—bottomhole treatment pressure.

change of slope is caused by changes of stiffness (lower compressibility) and a variation of leak-off behaviour (from bilinear to pseudo radial flow) of the system when the created fracture closes. When it starts to contact, as the fracture approaches closure, the fracture shows a residual conductivity due to the roughness of the wall's surfaces. With decreasing pressure, the effective stress on the fracture planes rises and the conductivity is reduced. This consolidation process can result in a smooth transition of the pressure slope, masking the actual closure event [16].

The p_c represents a global value determined from large-scale fracturing, valid for the fractured zone, where a significant net fracturing pressure share has to be accounted for. Therefore it can not be directly compared with individual values of $\sigma_{h\ min}$ (local value) determined via small-scale micro-fracturing [16] or laboratory data. It is rather the average of the minimum principal stress of the zone covered by the created fracture(s).

At least for the lower interval, it was found that with 8.4 MPa the effective closure stress ranges only slightly above in situ pore pressure. The second interval showed significantly a higher closure stress value. The presence of inter-layered clay (higher anisotropy) and clearly lower permeability account for the initially higher stress state (Fig. 4). Additionally and according to Biot's theory, the stress state in the second (upper) interval might have been altered due to a large-scale change in pore pressure as a consequence of the treatment of the lower interval earlier. As the two intervals are spatially very close to each other and no natural hydraulic barrier is present in the reservoir, an interaction in terms of a pressure diffusion process seems very likely. The identified stress gradients dp_c/dz (12.7 and 14.3 MPa/km, respectively) compare very well with stress values determined by Lempp et al. [17] and Röckel et al. [18] for sub-salinar clastic reservoir rocks in the North German Basin. Although closure stresses could be matched by subsequent fracture modelling, further diagnostic treatments such as "pump-in flow-back" and hydraulic impedance testing [19] should be applied to confirm results retrieved from pressure decline analysis. The latter delivers representative values of dp_c/dz only for pure fluid treatments and requires knowledge about in situ fluid properties (viscosity, leak-off coefficient, density).

With the two most important parameters: closure stress gradient and permeability of the pay zone and

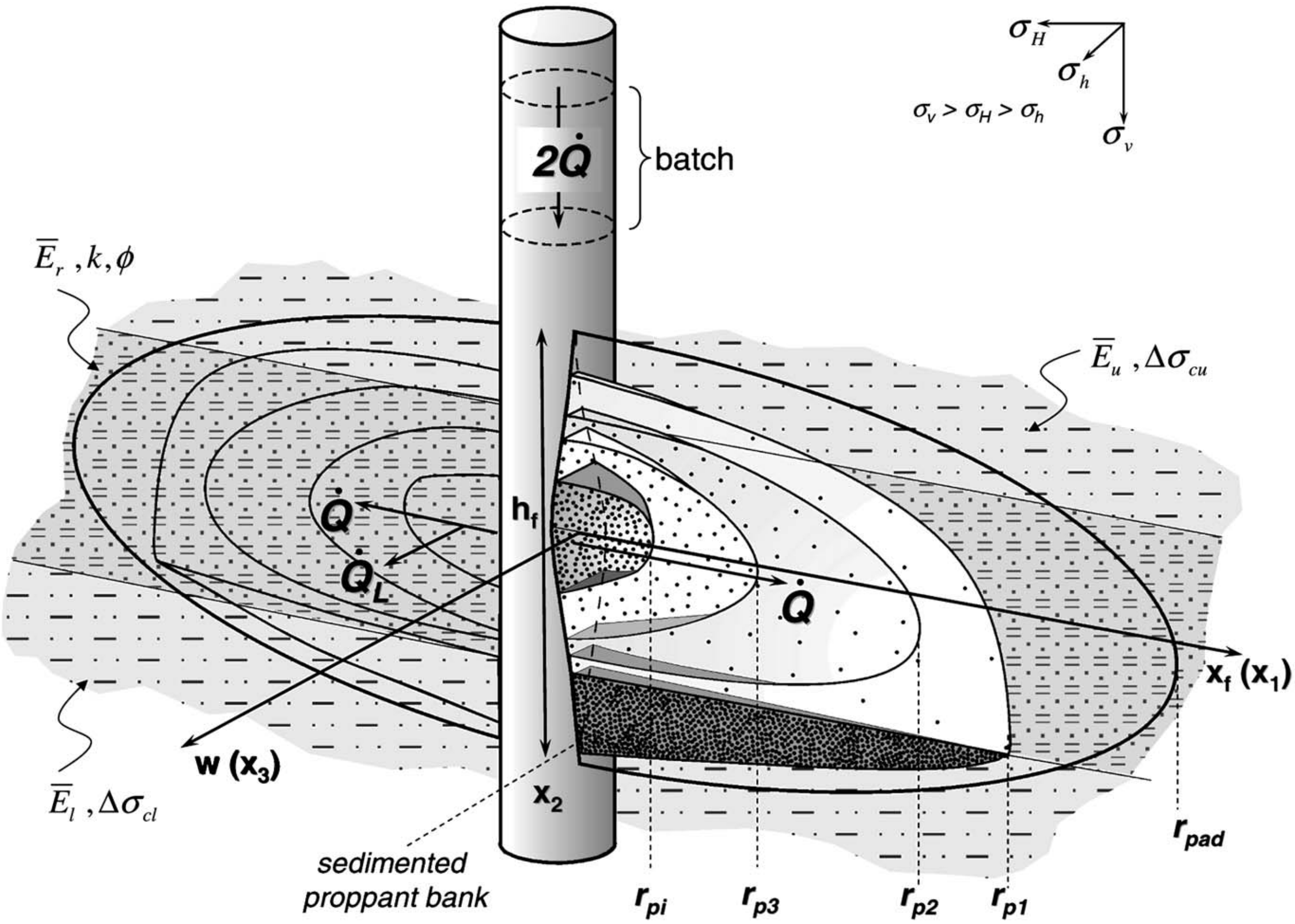

Fig. 5. Schematic picture of the three-dimensional fracture model with its most important influencing parameters: Q—injection rate; σ—stress magnitude; E—Youngs modulus; k—permeability; $\varnothing$—porosity and the fracture dimensions: w—width, x_f—half length, h_f—height, r_p—fluid penetration radii; subscripts: $_{h,H}$—horizontal, $_v$—vertical, $_c$—closure, $_u$—upper, $_r$—reservoir, $_l$—lower [3].

surrounding layers, the fracturing process could be modelled (Fig. 5). A three-dimensional fracture simulator (FRACPRO^{TM}) was used to model fracture dimensions (Fig. 6) by matching net treatment pressures. A detailed description of this analysis can be found in Legarth [3]. 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 setup subsequent production schedules and—as real-time modelling with the applied simulator becomes possible—to optimize fracture and treatment design (e.g. adapt fluid and proppant stages) on site.

4.2. Transient production analysis

Hydraulic propped fractures were created with treatments in both intervals. Before and after stimulation production tests (casing lift test with nitrogen) were performed to determine the stimulation effect. In Fig. 7 pressure responses and flow rates are shown for both tests.

From an interpretation of transient production periods, a significant increase in productivity is evident. Considering a production time of 10 h in both tests the productivity increases from 1.2 to 2.1 m^3/h MPa, representing a factor of about 1.8 [3]. To characterize changes in the hydraulic system build-up periods have been analysed. Before stimulation the peak in the derivative indicates a significant skin. After stimulation almost no peak is observed indicating a reduction of skin. Per definition skin stands for a zone of reduced permeability around the wellbore, resulting from damage due to drilling, completion, and/or production practices.

From the level of the first order derivative of a build-up test the formation transmissibility can be estimated. This is possible when the curve flattens out indicating that radial flow conditions have been reached. Comparing these levels before and after a stimulation treatment the change in transmissibility can be analysed. In the

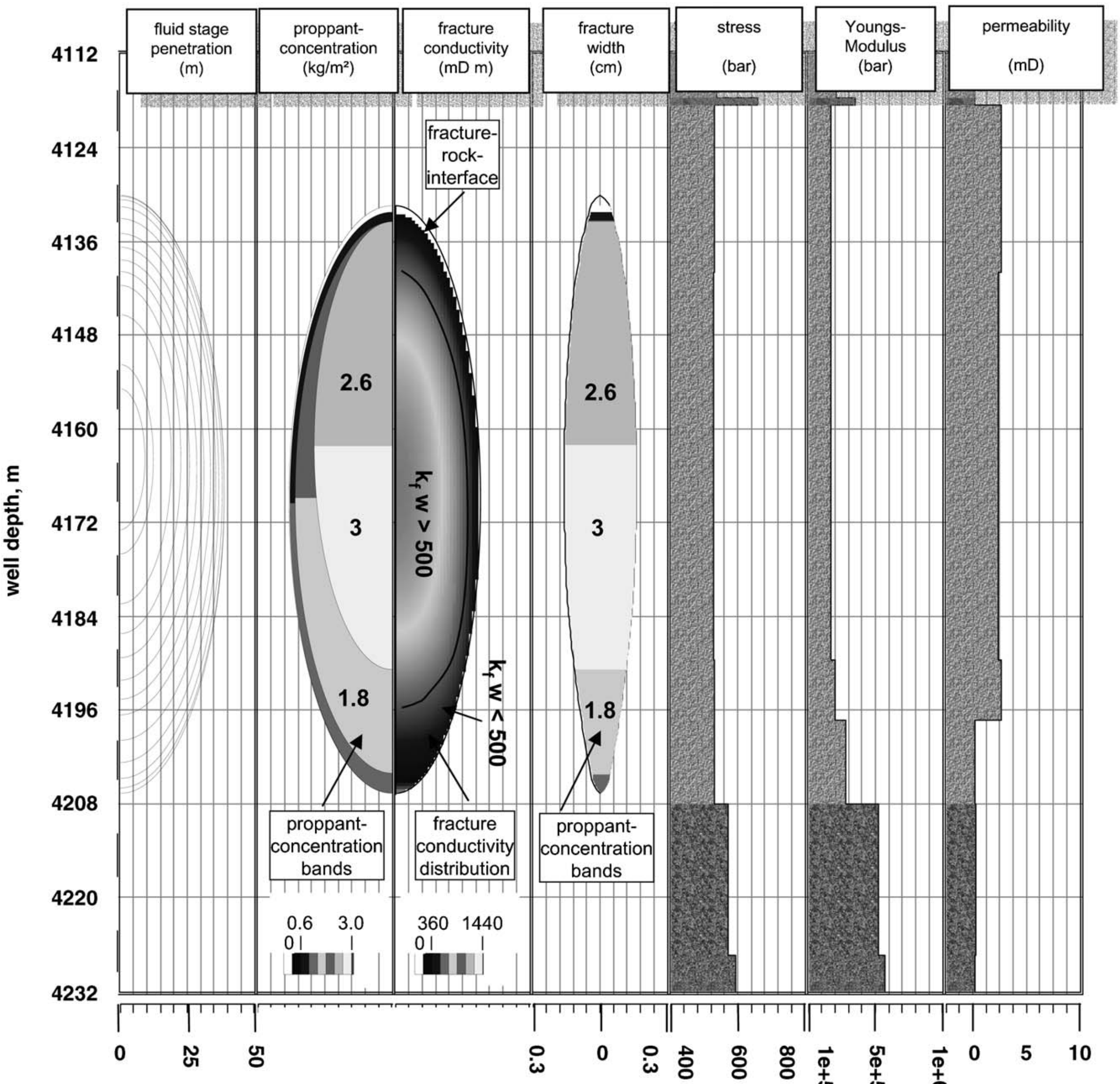

Fig. 6. Fracture dimensions from three-dimensional fracture modelling (fracture properties: proppant concentration ca. 1.9 kg/m^2; conductivity 300—500 mDm; half-length ca. 32 m; height: ca. 72 m; max. width: ca. 0.16 cm); first fracturing interval 4190 m–4130 m [3]; axis titles and units on top of graph.

given case the derivative of the build-up after the stimulation treatments shows an upward trend, no horizontal level is reached. This behaviour can have two reasons: (1) build-up monitoring was too short (radial flow regime not reached) or (2) reservoir boundaries have been reached. Thus, no direct conclusion can be drawn concerning the change in transmissibility of the production zones. Evaluation of longer build-up periods is necessary in order to reach a reliable interpretation.

No distinct hydraulic signatures of fractures (slope of $\frac{1}{2}$ or $\frac{1}{4}$) in the log–log plot after stimulation are observed. Probably less conductive or short fractures were created and hydraulic characteristics of fractures are masked by a large wellbore storage. To fit pressure responses of the well an inhomogeneous reservoir had to be assumed. For instance, good matches are obtained using a composite model with two consecutive zones with radial decreasing transmissibility Fig. 7 [20].

Productivity increase results from a skin reduction due to creation of artificial fractures. In contrast to our expectations the well test results do not reveal that additional high permeable zones were connected to the wellbore.

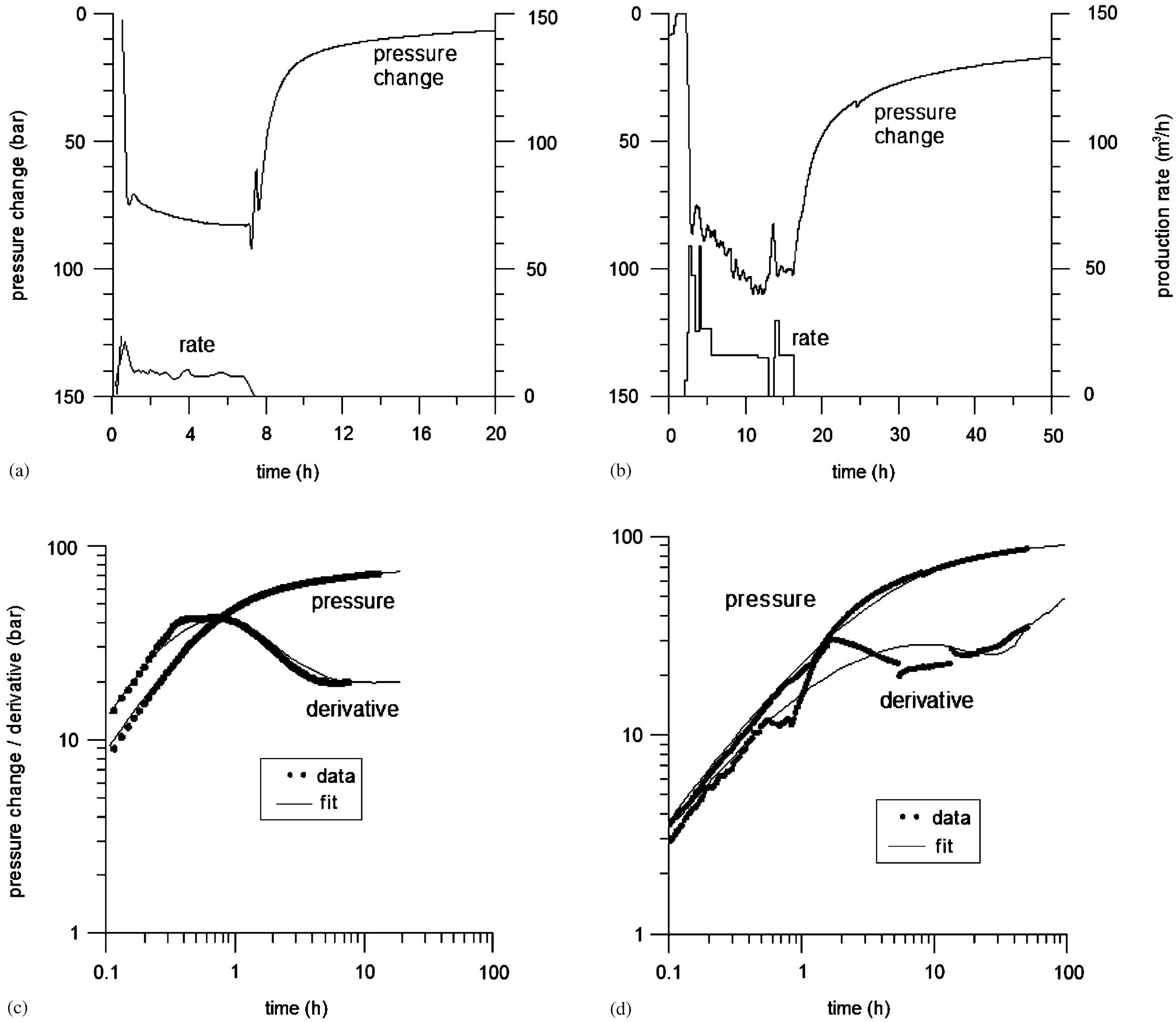

Fig. 7. Pressure change and production rate for the lift test before stimulation (a) and after stimulation (b). Diagrams (c) and (d) show the log–log plot for the build-up periods before and after stimulation, respectively. For pressure derivative, the superposition time was used. In (c) and (d), the fit curves are obtained assuming a radial composite model (c). The following important parameters were obtained by nonlinear regression—before stimulation (c): skin = −1.0; after stimulation (d): skin = −4.9. Transmissivity of the inner zone is in the range of (0.5–1.1)E-13 m^3 and transmissivity in the outer zone is in the range of 1–7E-14 m^3. According to the assumed composite model transition between inner and outer zone occurs at a radial distance between 30 and 80 m [20].

5. Fracture performance analysis

The stimulation effect of a hydraulic fracture in a porous-permeable matrix is estimated by analytical modelling. The applied model [11] is valid for fracture half-lengths that are less than one-half the reservoir drainage radius and therefore suitable for the given case. From modelling the theoretical maximum achievable stimulation ratio (expressed as the folds of increase—FOI) is determined. FOI is the ratio between initial reservoir productivity to and reservoir productivity after stimulation. Plotted versus dimensionless fracture conductivity (F_{CD})—as a measure for the created permeability contrast between fracture and matrix—it reveals its sensitivity to specific fracture parameters as conductivity (product of fracture permeability k_f and fracture width w) and half-length (x_f) (Fig. 8). The most important conclusions drawn from this analysis are:

(1) stimulation ratios are individual values and have to be determined for each reservoir/fracture setting
(2) stimulation ratios increase with increasing F_{CD} reaching a half-length dependent maximum.
(3) For high values of F_{CD}—this can also be caused by low matrix permeabilities (k)—an increase in stimu-

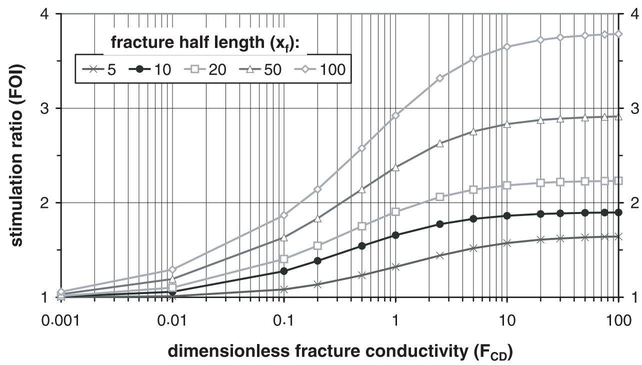

Fig. 8. Stimulation ratio of a vertical fracture with variable conductivity and half length in a porous–permeable matrix under pseudo-steady, radial inflow conditions, with $\ln(r_e/r_w) = 8.75$; with r_e—reservoir drainage radius, r_w—wellbore radius.

lation ratio can only be achieved by increasing fracture length (fracture dimensions) which is strongly limited by technical and economical feasibility.

The initial reservoir productivity ($\mathrm{PI}_{\mathrm{pre-frac}}$) gets multiplied by the calculated FOI revealing post-frac productivity ($\mathrm{PI}_{\mathrm{post-frac}}$). In the given case the $\mathrm{PI}_{\mathrm{post-frac}}$ remained insufficient with respect to predefined objectives. Simulating fracture performance (with FRAC-PRO$^{\mathrm{TM}}$) according to the modelled fracture dimensions (Fig. 6) values for the FOI between 7 and 8 were expected. The reason for the mismatch between observed (FOI = 1.8) and modelled (FOI = 7–8) can be explained by re-modelling fracture performance taking various hydraulic and mechanical effects into account [3], which will be described in the following sections.

5.1. Non-darcy flow effects

The developed reservoir is situated below the gas–water contact (GWC) with large lateral, stratiform extensions. Measurements on cores showed clear evidence for the presence of pay zone porosities between 5% and 15% and transmissibilities of several Darcy-Meter ($10^{-12}\,\mathrm{m}^3$) [3]. Therefore, a poor reservoir is unlikely to account alone for the observed lack in productivity. Obviously there are several effects with its origin in an impaired fracture performance which jointly inhibit productivity increase.

At first non-Darcy flow effects (NDF) [21] have to be considered. The occurrence of non-Darcy flow effects leads to a reduction of effective in situ transmissibility as a result of inertial pressure drops in flow channels. They are caused by continuous de- and acceleration of fluid molecules travelling along tortuous flow paths through interconnected pores and also in the proppant pack. They begin to appear at a Reynolds number (N_{Re}) above 1 (NDF criterion) considering a bent tube model [22]. N_{Re} is defined as

$$N_{\mathrm{Re}} = \frac{dv\rho}{\mu}, \tag{1}$$

where d represents the characteristic linear dimension of the flow regime, v the Darcy flow velocity, ρ the density of the flowing fluid, μ is the flowing-fluid viscosity.

The higher N_{Re} the smaller becomes the remaining transmissibility [23]. The magnitudes of NDF were calculated for a fluid production rate of up to $25\,\mathrm{m}^3/\mathrm{h}$ as it was observed during production tests. Model parameters like geometry of the well, reservoir and fracture parameters are given in Fig. 9 and 10. Even for high rates N_{Re} stays small for flow in the matrix compared to in the fracture. At the specified rate the corresponding N_{Re} reaches values, depending on the given model, far below 1 for flow in the matrix and orders of magnitudes higher (clearly above 1) in the vertically oriented, proppant filled bi-wing fracture as primary flow path in the system. In the given case and for rates between 25 and $100\,\mathrm{m}^3/\mathrm{h}$, N_{Re} reaches the following values: 5×10^{-3}–2×10^{-2} in the matrix (average grain diameter $5\,\mu\mathrm{m}$), and between 6×10^{1}–3×10^{2} in the fracture, respectively. Thus, it is especially important to account for NDF when analysing transient production tests in low permeability reservoirs where the inflow is dominated by linear and bi-linear flow through the fracture in the early and mid-time region. For long production times—depending on individual reservoir properties—pseudo radial inflow conditions will prevail in the reservoir. The matrix will take its share in the production. Independent of flow regime, NDF cannot be neglected for flow within the fracture. This is even valid if the fracture itself is only sharing very little in the entire

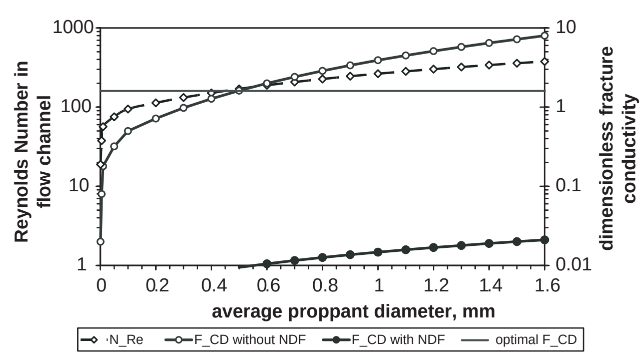

Fig. 9. Deterioration of fracture performance by non-Darcy flow effects; fracture geometry taken from Fig. 5; fluid production rate: $25\,\mathrm{m}^3/\mathrm{h}$; flow channel geometries are calculated considering a dense spherical pack of grains (proppants) in a bi-wing fracture; NDF criterion is reached for a grain size above 0.5 mm; F^{*}_{CD} is far below the design optimum of 1.6. Model parameters are $k = 2\,\mathrm{mD}$, $h_f = 72\,\mathrm{m}$, $x_f = 32\,\mathrm{m}$, $w = 0.0016\,\mathrm{m}$, $F_{\mathrm{CDopt}} = 1.6$.

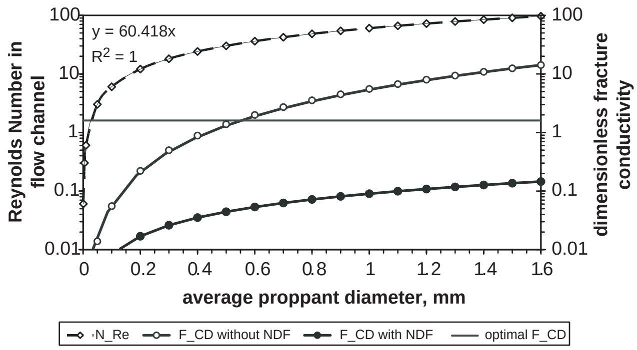

Fig. 10. Deterioration of inflow performance by non-Darcy flow effects in re-designed fracture with larger width and at a lower fluid production rate of $25\,m^3/h$; flow channel geometries are calculated considering a dense spherical pack. Model parameters are $k = 2\,mD$, $h_f = 72\,m$, $x_f = 36\,m$, $w = 0.005\,m$, $F_{CDopt} = 1.6$.

flow due to the flow channel diameter relationship (matrix vs. fracture ~1:100). Using the approach of Gidley [23] the dimensionless fracture conductivity calculated can be corrected for non-Darcy flow effects (Eq. (2)).

$$F_{CD} = \frac{k_f w}{x_f k}, \tag{2}$$

$$F^*_{CD} = \frac{F_{CD}}{1 + N_{RE}}, \tag{3}$$

where F^*_{CD} represents the corrected dimensionless fracture conductivity. It is expressing the created contrast between fracture and formation permeability. An optimum fracture design is reached at a value of 1.6 for the F_{CD} [9]. Fig. 9 reveals that already for very small proppant diameters N_{Re} exceeds the NDF criterion. For a re-designed fracture (Fig. 10) with larger width this is omitted until much larger proppant diameters. As a consequence, the corresponding F^*_{CD} is diminished and the inflow enhancement strongly deteriorated. Fig. 9 presents values of F_{CD} and F^*_{CD} for the modelled fracture (Fig. 6) showing a potential severe reduction of fracture conductivity as a result of NDF.

This leads to the following conclusion with respect to NDF: given that reservoir characteristics remain unchanged, the flow conditions will be improved in case one or several of the following are provided: higher remaining fracture widths and heights, larger fracture height vs. length relationship, larger proppant diameter, less heterogeneous proppant pack (smaller grain size range), or smaller production rates.

All of the above conditions aid in either increasing the inflow area or decreasing fluid velocity per flow channel that leads to a direct reduction of NDF. The ratio of height of the fracture and its length is critical, because it is difficult to control. It strongly depends on the natural fracture compliance. Ideally, the fracture should be very short and at the same time covering the whole pay-zone in height. An aggressive screen-out design might lead to that geometry but at the same time bear a high risk of treatment failure. The simplest fracture geometry to assume for design purposes (no compliance) is the radial or "penny-shaped" fracture with $x_f = \frac{1}{2}h_f$.

The production rate resembles the main design parameter but its range is limited by overall production requirements in order to guarantee an economic energy conversion ($q > 20\,kg/s$). The only possibility in this case would be to realize a multi-well scenario with a commingled production, and splitting up the required flow rate over number of producers. As drilling wells generally represent the highest share of the overall investments in geothermal exploitation this can only be a solution for low-cost-drilling locations (e.g. shallow reservoirs).

Thus, fracture dimensions are the remaining primary design parameters that can be varied according to treatment set-up.

- Fracture widths and heights increase with net treatment pressure.
- Fracture width increase by tip-screen out design (fracture inflation).

Still, the parameters are not arbitrarily adjustable. Realistic conditions have to be assumed. An effective proppant pack (multi-layering) is reached when achieving about $10\,kg/m^2$ ($2\,lb/ft^2$) proppant concentration in the fracture (at a bulk density of ordinary high strength proppants of about $2000\,kg/m^3$ this results in a fracture width of 5 mm). Proppant strength decreases with increasing grain size. More fines are generated when larger proppants are exposed to high effective stresses. Nevertheless, pumping an average grain diameter of 1 mm is realistic considering modern proppant technology. A proppant pack optimization towards larger grain sizes can even be further achieved if considering that in geothermal wells the drawdown (proportional to effective stress) is anyway strongly limited by production efficiency criteria. The result for such a re-designed fracture (width increment factor: 3.125) is given in Fig. 10. Re-design was achieved by pure modelling and was not field implemented. Nevertheless, it can be analysed that even for a strongly improved fracture geometry the F^*_{CD} remains below the design criterion due to NDF.

The mentioned aspects yet neglect the long-term behaviour of the propped fracture under drawdown conditions. Additional measures such as proppant flowback control and slurry under-displacement have to be taken into account for a broader design needed in the actual field case.

5.2. Proppant pack damage

Besides non-Darcy flow effects, mechanical and size effects have to be discussed as causes for missing the designed productivity goal. The first assumption is a fracture creation without properly connecting productive zones to the well [20]. This can be caused by either a fracture that is too short in order to bypass damaged zones in the vicinity of the wellbore (skin). Or a fracture with appropriate length but low conductivity was created so that the intended permeability contrast to the matrix was not achieved. A combination of both scenarios is also possible. Another explanation is a fracture with initial proper dimensions, but with a conductivity that was deteriorated as a consequence of proppant crushing, embedment and proppant flow-back during drawdown. Other possible reasons for the phenomena such as proppant convection and lacking tie-back, multiple fracture as well as out of pay zone growth are referred to in other cases [24–26]. Finally, all assumptions need to be individually checked for plausibility. This was done by including the damaging effects in the fracture and the reservoir model and trying to establish an adequate pressure match (fracture performance modelling). It turned out that the observed behaviour could only be adequately explained by either a severe post-treatment conductivity reduction or a missing tie-back of the fracture—a so-called choked fracture—to the well [3].

Proppant crushing and embedment due to increasing effective stresses during drawdown lead to a reduction in fracture width and thus can cause that reduction of fracture conductivity (Fig. 11). Theoretically proppants get crushed or embedded in the rock matrix depending on the relationship between their mechanical strength and that of the rock [27]. As rock is an anisotropic, inhomogeneous medium, especially when naturally fractured, both effects are likely to occur at different parts of the fracture-rock-interface.

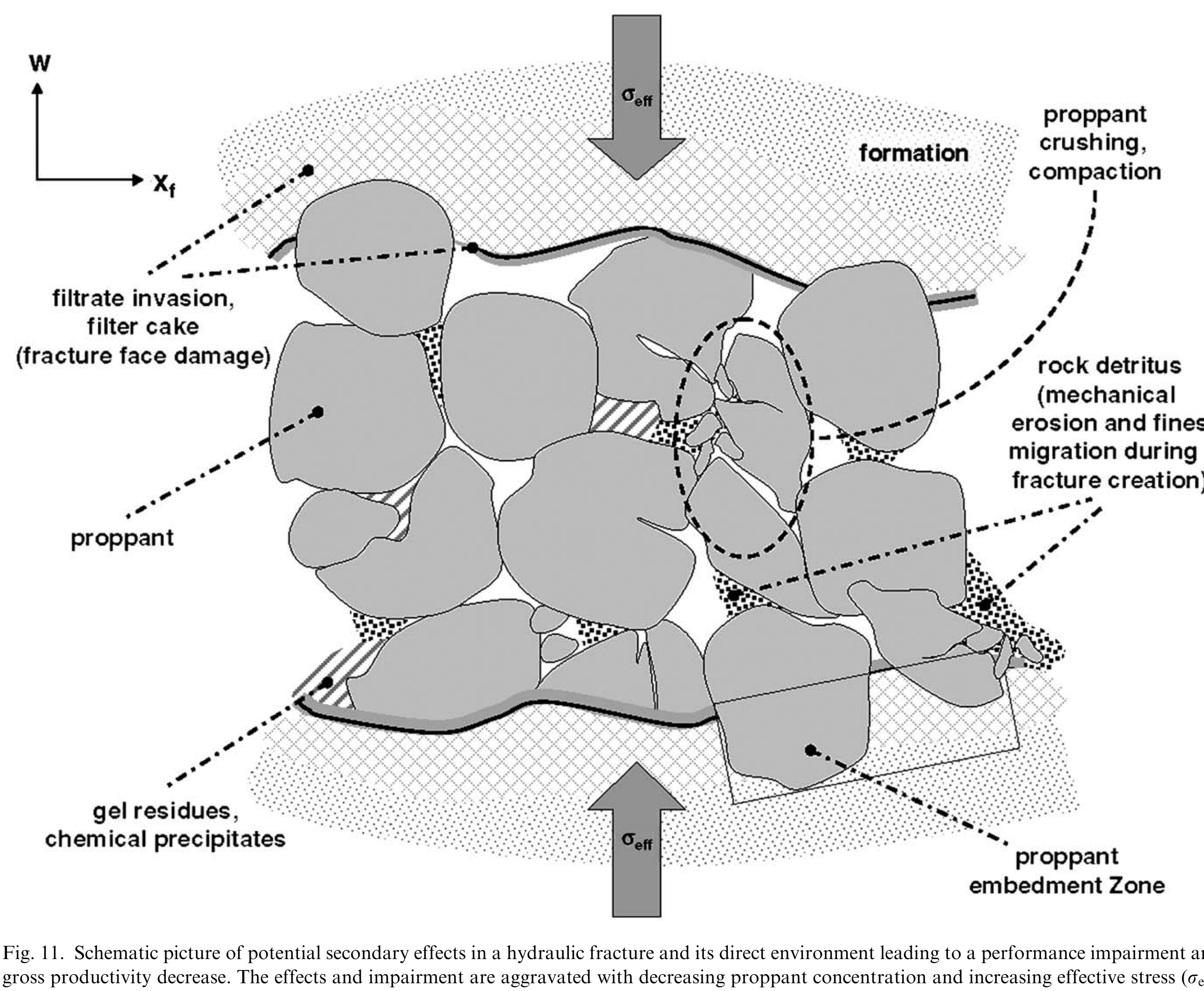

Fig. 11. Schematic picture of potential secondary effects in a hydraulic fracture and its direct environment leading to a performance impairment and gross productivity decrease. The effects and impairment are aggravated with decreasing proppant concentration and increasing effective stress (σ_{eff}) on the fracture walls [3].

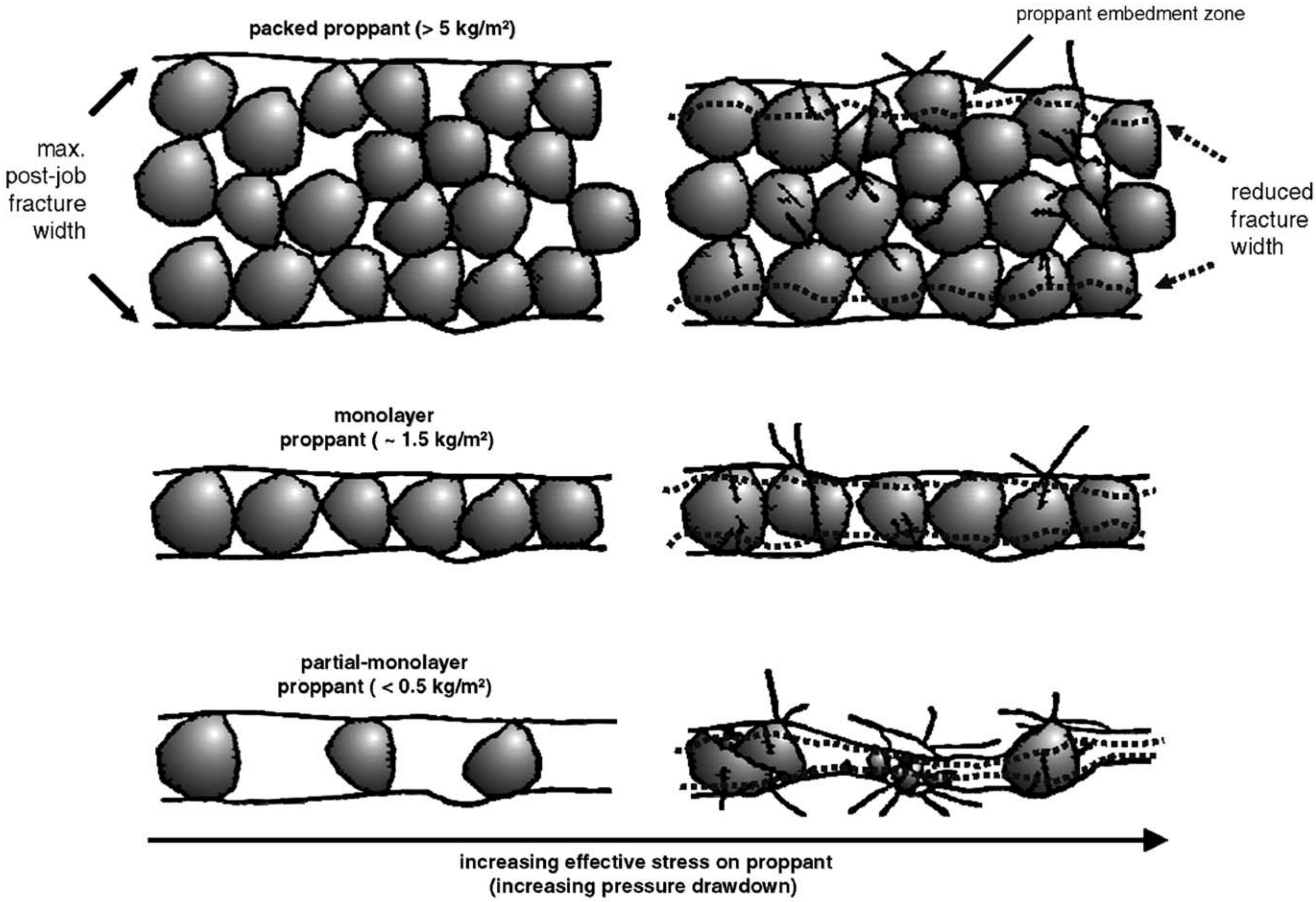

Fig. 12. Potential post-job proppant pack damage due to proppant crushing and embedment for different proppant concentrations with increasing effective stresses during drawdown; proppant pack classifications after Sato et al. [27].

The lower the concentration of proppants in the fracture the more severe these effects are [27]. Especially for partial monolayer proppants the stress concentration on single grains is maximised (punctual loading). Three-dimensional modelling of the conducted fracture treatments showed maximum post-job proppant concentration of only about 1.9 kg/m^2. This value is slightly above the monolayer criterion (Fig. 12) and consequently does represent a sub-optimal dimensioned fracture propping in this reservoir. Therefore, fracture conductivity is strongly limited and potentially inflow restrictions are not completely by-passed. Additionally, proppant flow-back occurred during production tests that further diminishes proppant concentration in the vicinity of the wellbore. Leaving the fracture end insufficiently propped (partial-monolayer) or even unpropped can result in partial fracture closure and further production impairment.

Finally, the reasons described for an observed inflow performance impairment (less productivity increase as expected) caused by hydraulic and mechanical effects would not have been necessarily less without using proppants. The risk of fracture closure and a hydraulic decoupling, especially in the near-wellbore region, is even enhanced. Effective (highly conductive and sustainable) self-propping mechanisms are not yet proven for sedimentary geothermal reservoirs.

6. Conclusions

The open hole hydraulic proppant fracture treatments were successful: Technical feasibility of the fracturing concept was proven, propped fractures were created and inflow performance of the well was enhanced.

In contrast, the anticipated stimulation ratio and post-fracturing productivity could not be achieved. Probably fractures were sub-dimensioned and do not properly connect existing productive reservoir zones to the well. The main reason for insufficient fracture dimensions is the initial, moderate fracture design that was targeted at risk reduction. For an effective productivity enhancement additional hydraulic proppant fracture treatments in the Rotliegend sandstones with increased proppant loading are necessary in order to create long-term conductive fractures. Moreover, post-fracturing production tests have to be performed moderately at lower depressions to mitigate additional proppant pack damage resulting in fracture conductivity reduction and severe productivity impairment. Non-Darcy flow effects deteriorate the achievable well productivity by reducing effective fracture conductivity. This can in parts be avoided by adapting the fracture treatment concept and design.

Furthermore, treatment analysis due to low effective fracture closure and net pressure shows overall favourable conditions for fracturing in the potential pay zone. Further hydraulic tests should be conducted in order to further confirm these findings.

Thus, the key question of whether the target zones also represent pay zones cannot be fully answered. What can definitely be stated is that the stimulation potential of the Rotliegend sandstone reservoir is not yet exhausted and the maximum achievable productivity values are not yet reached. This maximum can be theoretically defined by pre-fracturing modelling and is limited by reservoir properties and technical and economic feasibility. In any case, especially when thinking of a transfer of concepts to other but geologically similar locations, the applied technology does not lead automatically to success. Even considering an optimum stimulation design, at least moderate initial reservoir productivity is required ($>10\,m^3/h\,MPa$) to reach an efficient and economic fluid production. This is due to the fact that the stimulation effect of such treatments in the given geologic environment is bound between a level of approximately 2–4. Thus, the need for an adequate exploration becomes more crucial.

The hydraulic connection of further productive zones—in vertical and lateral direction from the investigated potential sedimentary pay zones—will yield an increase of overall transmissibility (*kh*) and could probably compensate lower primary productivity values. Considering a commingled production an efficient fluid production could still be reached.

Acknowledgements

The presented work is part of a multidisciplinary research project of GFZ Potsdam, BGR Hannover, GGA Hannover, TU Berlin and industrial partners (GTN Neubrandenburg, BWG Neubrandenburg, MeSy Bochum). It was funded by German governmental institutions BMWi (now BMWA), BMU, MWI and MWFK (BEO 0327063).

References

[1] Hurter S, Köhler S, Saadat A, Holl H-G, Rockel W, Trautwein U, Zimmermann G, Wolfgramm M, Huenges E. Stimulating low permeability aquifers: experiments in Rotliegend sandstones (NE Germany). Proceedings, geothermal resources council meeting, Reno, Nevada; 2002.

[2] Huenges E, Saadat A, Köhler S, Trautwein U, Hurter S. The in-situ geothermal laboratory Groß Schönebeck—learning to use low permeability aquifers for geothermal power. Proceedings of the 27th Stanford geothermal workshop, SGP-TR-171; 2002.

[3] Legarth B, Erschließung sedimentärer Speichergesteine für eine geothermische Stromerzeugung. PhD-thesis, Technical University Berlin, D83, Faculty VI: Civil Engineering and Applied Geosciences. Published as scientific technical report STR03/09. GeoForschungsZentrum Potsdam, Germany; 2003.

[4] Huenges E, Wolfgramm M. Sandsteine im in-situ-geothermielabor Groß Schönebeck—reservoircharakterisierung, stimulation, hydraulik und nutzungskonzepte. Scientific technical report STR04/03. Geothermie report 04–01; 2004.

[5] Bradley HB, et al. Petroleum engineering handbook. 3rd ed. Richardson, Texas: Society of Petroleum Engineers; 1992.

[6] Entingh DJ. Geothermal well stimulation experiments in the United States. Proceedings of the world geothermal congress 2000, Kyushu–Tohoku, Japan; 2000. p. 3689–3694.

[7] Campbell DA, Morris CW, Verity R. Geothermal well stimulation experiments and evaluation. SPE paper 10316. Proceedings of the 56th annual fall technical conference and exhibition. San Antonio, Texas: Society of Petroleum Engineers; 1981.

[8] Morris CW, Sinclair AR. Evaluation of bottomhole treatment for geothermal well hydraulic fracture stimulation. SPE Paper 11157. Proceedings of the 56th annual fall technical conference and exhibition. San Antonio, Texas: Society of Petroleum Engineers; 1982.

[9] Economides MJ, Oligney R, Valkó P. Unified fracture design. Alvin, Texas: Orsa Press; 2002.

[10] Mayerhofer MJ, Meehan DN. Waterfracs—results from 50 cotton valley wells. SPE paper 49104. Proceedings, SPE annual technical conference and exhibition, New Orleans; 1998.

[11] McGuire WJ, Sikora VJ. The effect of vertical fractures on well productivity. Trans AIME 1960;219:401–3.

[12] Cleary MP. Critical issues in hydraulic fracturing of high-permeability reservoirs. SPE paper 27618. Proceedings, European production operations conference and exhibition. Aberdeen, Scotland; 1994.

[13] Cipolla CL, Wright CA. Diagnostic techniques to understand hydraulic fracturing: what? why? and how? SPE paper 59735. Proceedings, SPE/CERI Gas Technology Symposium, Calgary; 2000.

[14] Nolte KG. Fracture design considerations based on pressure analysis. SPE paper 10911; 1982.

[15] Weng X, Pandey V, Nolte KG. Equilibrium test—a method for closure pressure determination. SPE/ISRM paper 78173; 2002.

[16] Economides MJ, Nolte KG. Reservoir stimulation. 2nd ed. Houston: Schlumberger Educational Services; 1989.

[17] Lempp C, Röckel T. Bohrloch- und Bohrkern-instabilitäten als indikatoren des regionalen spannungszustandes, Proceedings, 12. Nationale tagung für ingenieurgeologie, Halle, Germany; 1999.

[18] Röckel T, Lempp C. Der spannungszustand im norddeutschen becken. Erdöl Erdgas Kohle 2003;119(2).

[19] Holzhausen GR, Gooch RP. Impedance of hydraulic fractures: Ist measurement and use for estimating fracture closure pressure and dimensions. SPE paper 13892. Proceedings, SPE/DOE 1985 Low Permeability Gas Reservoirs, Denver; 1985.

[20] Tischner T, Legarth B, Huenges E. Stimulationsexperimente in den Rotliegend-Sandsteinen der Bohrung Groß Schönebeck: Ergebnisse zur hydraulik und gebirgsmechanik. Proceedings, der 7. Geothermischen Fachtagung, Waren a.d. Müritz; 2002.

[21] Forchheimer P. Wasserbewegung durch Boden. ZVDI 1901; 45:1781.

[22] Li D, Engler TW. Literature review on correlations of the non-Darcy coefficient. Society of Petroleum Engineers, SPE Paper

70015. Proceedings, SPE permian basin oil and gas recovery conference, Midland, Texas; 2001.

[23] Gidley JL. A method for correcting dimensionless fracture conductivity for non-Darcy flow effects. Society of Petroleum Engineers, SPE paper 20710, Proceedings 65th annual technical conference and exhibition of the society of petroleum engineers, New Orleans; 1990.

[24] Cleary MP, Fonseca A. Proppant convection and encapsulation in hydraulic fracturing: practical implications of computer and laboratory simulations. SPE paper 24825. Proceeding, 67th annual technical conference and exhibition of the society of petroleum engineers, Washington, DC; 1992.

[25] Berghofer K. Entwicklung und trends bei der fracstimulation von Rotliegend erdgasbohrungen. Proceedings 9801, DGMK-Frühjahrstagung 1998. Fachbereich Aufsuchung und Gewinnung, Celle; 1998.

[26] Aud WW, Poulson TD, Burns RA, Rushing TR, Orr WD. Lateral proppant distribution: the good, the bad, and the ugly of putting frac jobs away. SPE paper 56725. Proceedings SPE annual technical conference and exhibition, Houston; 1999.

[27] Sato K, Ichikawa M. Post-Frac analysis indicating multiple fractures created in a volcanic formation. SPE paper 39513. Proceedings SPE India oil and gas conference and exhibition, New Delhi; 1998.