

## A New Hybrid Simulation Approach to Evaluate the Efficiency of Hydraulic Stimulation Treatments

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**Keywords:** Enhanced Geothermal Systems (EGS), coupled simulation, Particle Flow Code, OpenGeoSys, Groß Schönebeck

### ABSTRACT

The development and operation of Enhanced Geothermal Systems (EGS) is governed by complex interactions of geological, hydraulic (H), mechanical (M), thermal (T) and chemical (C) processes occurring during a relatively short term stimulation phase and a long term production phase. An adequate representation of these highly non-linearly coupled and transient processes is only possible by numerical modeling.

To date, no single modeling approach is capable of sufficiently describing these coupled and transient dynamic processes. This paper introduces two modeling methods: (1) H-M coupled dynamic discrete element model by PFC2D (Particle Flow Code 2D) and (2) T-H coupled finite element model by OpenGeoSys (OGS). The two simulators are combined by an interface module in which the results of hydraulic stimulation modeling by PFC2D are passed on to OGS for long term T-H coupled flow simulation in the stimulated reservoir. The combination of these two simulators, therefore, provides relatively short-term reservoir behavior by hydraulic stimulation (stimulation phase) and long-term behaviors in production/circulation phase.

This paper describes the work flow of reservoir modeling using the hybrid simulator. A re-stimulation scenario of a volcanic rock layer in the in-situ geothermal laboratory Groß Schönebeck (Northeast German Basin) is given as demonstration application.

### 1. INTRODUCTION

Due to the limited amount of hydrothermal resources, most of the earth's heat can only be recovered by means of Enhanced Geothermal Systems (EGS); i.e. enhancing the fluid flow rate through hot but low permeable rock with the help of different stimulation methods (Schulte et al., 2010). Besides matrix acidizing, acid stimulation (Kalfayan, 2007), and thermal stimulation methods (Grant et al., 2013), hydraulic stimulation techniques are commonly used to enhance reservoir productivities of different types of unproductive geothermal reservoirs (Tester et al., 2006; Schulte et al., 2010; Zimmermann et al., 2010; Schindler et al., 2008). In this study we present a hybrid numerical simulation approach to model hydraulic stimulation treatments in jointed rock masses and to evaluate the subsequent productivity enhancement due to the stimulated fracture network.

During a hydraulic stimulation treatment, fluids (with or without proppants) are injected into a target formation at certain flow rates, over the course of some hours up to some weeks, in order to induce new hydraulic (tensile) fractures by generating higher bottom hole pressures than the formation can withstand (e.g. Yew, 1997), and/or improve the permeability of in-situ fracture networks due to a self-propping effect resulting from the shear motion of the fracture faces (and the fracture roughness) of critically oriented fractures (e.g. Narayan et al., 1998).

This phase of EGS development is governed mainly by hydraulic and mechanically-interacting processes that are influenced by the geological setting, rock properties, and the treatment parameters. During longer treatments (>hours) and with high temperature differences, thermal effects might need to be considered as well (Grant et al., 2013).

Since the hydraulic, mechanical, thermal, and chemical processes governing both hydraulic stimulation treatments and heat production from the stimulated reservoir are very complex, numerical modeling is often the best option to study and evaluate these processes. However, current numerical modeling approaches cannot handle the complex interaction between all these processes together. Specific methods are more suitable to handle certain processes than others. This is especially true in the oil and gas industry, but also for geothermal applications, commercial pseudo 3D, planar 3D, or full 3D hydraulic fracturing simulators such as FRACPRO (Cleary, 1994), MFRAC (Meyer, 2011) or GOHFER (Barree, 1983) are routinely used for prediction, real-time analysis, and evaluation of hydraulic stimulation treatments (Warpinski et al., 1994; Weijers et al., 2005). These simulators are based on the two analytical 2D models KGD (Khristianovich and Zheltov, 1955; Geertsma and de Klerk, 1969) and PKN (Perkins and Kern, 1961; Nodgren, 1972) and are only calculating the tensile opening of a new crack in an intact rock mass or a tensile opening of pre-existing natural fractures that are perpendicular to each other (e.g. MSHALE; Meyer and Bazan, 2011). Adachi et al. (2007) gave a brief history of hydraulic fracturing simulation.

In an earlier study we pointed out two major concepts that the above models are missing to adequately model hydraulic stimulation treatments in naturally fractured basement rocks (Hofmann et al., 2013):

- (1) A representation of an arbitrary distribution and shape of pre-existing and induced fractures and
- (2) shear failure of pre-existing fractures in addition the tensile opening of new fractures.

Different modeling approaches are currently followed that fulfill these criteria. Examples are a variational approach by Chukwudozie et al. (2013), extended finite element methods (X-FEM; e.g. Shakib and Jalalifar, 2013), or discrete fracture network models (DFN; e.g. Williams-Stroud et al., 2012). Another technique is the Discrete Element Method (DEM), which became one of

the promising approaches to study hydraulic fracture development in rocks with heterogeneous and complex in-situ fracture networks. Codes like UDEC (Itasca, 2011)/3DEC (Itasca, 2013) and PFC2D (Itasca, 2008)/PFC3D (Itasca, 2014) have been increasingly used in the past years to investigate water fracturing treatments performed in geothermal settings in two and three dimensions (e.g. Riahi and Damjanac, 2013; Riahi et al., 2014; Bradford et al., 2013; Hazzard et al., 2002; Yoon et al., 2013; Yoon et al., 2014). In the presented hybrid simulation approach, PFC2D is used to simulate the hydraulic stimulation treatments because it can model coupled fluid-mechanical behavior including fracture initiation and propagation, slip and opening along joints in a pre-existing discrete fracture network (DFN). Further details about PFC2D are given in **Section 2.1**.

After the stimulation, in the production or circulation phase, hot fluid is flowing through the stimulated fracture network to the production well(s) and is pumped to the surface where its heat is extracted. The cool fluid is then re-injected into the formation by one or more injection well(s). On its way through the fracture network from the injection well(s) to the production well(s) the fluid is heated up again by the hot rock. This circulation phase is governed by hydraulic, thermal, mechanical, and chemical processes and geological factors that are all influencing each other. Mostly, only hydraulic and thermal processes are simulated (e.g. Blöcher et al., 2010; Hofmann et al., 2014a; Hofmann et al., 2014b) because pressure and temperature are the main parameters of interest. Currently, several approaches are being developed that include some mechanical and chemical processes as well (e.g. TOUGH-FLAC – Rutqvist and Tsang, 2003; TOUGH-REACT – Shevalier et al., 2012; OpenGeoSys - Kolditz et al., 2012).

There are three main approaches for reservoir simulation. The most common way to model temperature and fluid flow is the (1) Finite Difference Method (FDM, e.g. ECLIPSE – Schlumberger, 2008; TOUGH2 – Pruess, 1991; CMG STARS – Computer Modeling Group, 2011). Specifically for large, multiwell, heterogeneous, multiphase simulations the (2) streamline method may be used (e.g. Thiele et al., 1997; Johansen et al., 2013). Finally, if mechanical effects need to be considered as well and complex geometries need to be included, the (3) Finite Element Method (FEM) is most suitable (e.g. TOUGH-FLAC; Rutqvist and Tsang, 2003). For the presented hybrid simulation approach, the open source FEM code OpenGeoSys ([www.opengeosys.org](http://www.opengeosys.org), Kolditz et al., 2012) is used to model the coupled thermo-hydraulic reservoir behavior. Additionally, mechanical and chemical processes can potentially be included.

Commonly, hydraulic stimulation simulations are performed separately from the simulation of the thermal and hydraulic behavior during production/circulation (e.g. Blöcher et al., 2010 and Zimmermann et al., 2009). However, an interface between both simulators is often missing such that the simulated fracture geometry is approximated by simple geometrical objects in the reservoir simulator (e.g. Hofmann et al., 2014). Hybrid simulation approaches are at least two codes that are usually coupled (certain variables of one code are updated based on the results of the other code) after each time step (e.g. Rutqvist and Tsang, 2003). However, the hybrid simulation approach presented in this paper uses only the final results of the hydraulic fracturing simulations as reservoir properties for the reservoir simulations and interactions and data transfers during the simulation are not taken into account.

In this paper, a new hybrid simulation approach for the subsequent coupling of the DEM simulator PFC2D and the FEM code OGS is presented. An interface is therefore introduced that converts the output from PFC2D directly to input files of OGS. The next section describes the two simulation tools followed by a detailed explanation of the developed interface. To show the applicability of the proposed hybrid simulation approach, an exemplary simulation of a stimulation treatment (pre-treatment in an additional well followed by a main treatment in the injection well) in the volcanic rock layer of the geothermal research site Gross Schönebeck is presented.

## 2. DESCRIPTION OF THE NUMERICAL SIMULATORS

### 2.1 Hydraulic Stimulation Model (DEM)

The two-dimensional discrete element method (DEM) simulator Particle Flow Code 2D (PFC2D; Itasca, 2008) is used to simulate the hydraulic stimulation treatments. The 3D rock mass is represented in 2D by an aggregate of circular particles which are bonded together at their contact points. These bonds can break in Mode I (tensile) or Mode II (shear) under an applied load. The flow of a viscous fluid is simulated by assuming that each bonded particle contact is a flow channel that connects two fluid reservoirs that can store pressure (**Figure 2**, left). The fluid flow rate is governed by the cubic law assuming laminar flow between two smooth parallel plates. Discrete pre-existing joints are represented by the smooth joint contact model (Mas Ivars et al., 2008).

More details about PFC2D are given by Potyondy and Cundall (2004). Detailed descriptions of the fluid flow algorithm and the representation of discrete in-situ joints that were used are given by Yoon et al. (2014).

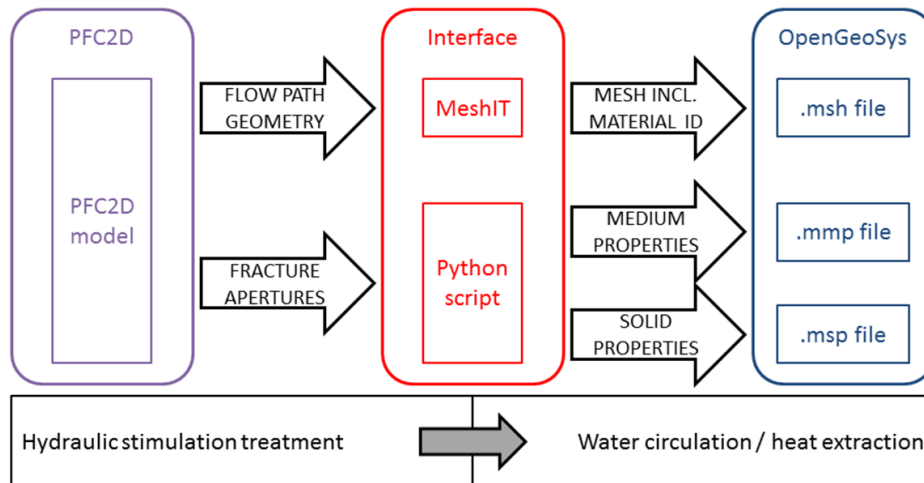
### 2.2 Reservoir Simulation Model (FEM)

The thermal and hydraulic behavior of the reservoir is subsequently modeled using the open source FEM-based simulator OpenGeoSys (OGS; Kolditz et al., 2012). OGS is able to superimpose permeable discrete fractures on a continuous volume representing the porous rock matrix (Cacace et al., 2013). Fluid flow (primary variable: pressure  $p$ ) and heat transport (primary variable: temperature  $T$ ) in fractured porous media are described by partial differential equations that are solved based on initial and boundary conditions. 2D and 3D discrete fractures are idealized as lower-dimensional geometric objects (e.g. represented as triangles; Watanabe et al., 2012). Fracture elements and porous media elements share the same nodes. Further details about governing equations and numerical schemes in OGS are given, e.g., by Watanabe et al. (2010) and Watanabe et al. (2012).

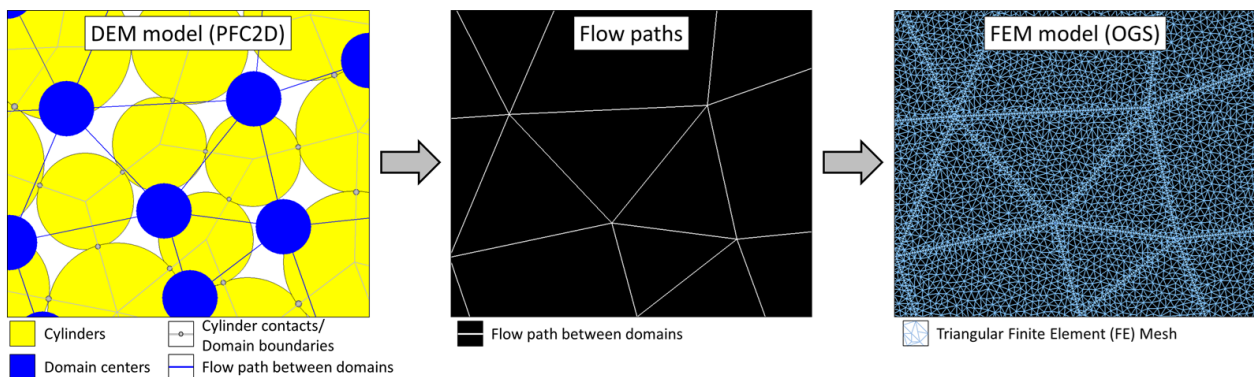
## 3. INTERFACE BETWEEN DEM AND FEM

In order to import the PFC2D simulation results to OGS, an interface was developed (**Figure 1**). This interface consists of two separate parts: (1) creating a FE mesh based on the flow channel geometries and specifying a separate material ID for each discrete fracture and the rock matrix (**Figure 2**), and (2) assigning material and solid properties to each material group (the matrix and the fractures). The meshing was done using an adapted version of the meshing tool MeshIT (Blöcher et al., 2010). The adapted version of this software automatically identifies each discrete fracture as a separate material and builds a triangular 2D mesh with

refinement around the discrete fracture elements. The required output data from PFC2D are the coordinates of the start ( $x_1, y_1$ ) and end ( $x_2, y_2$ ) points of each flow channel. Each fracture element and the matrix are assigned a different material group for whose material and solid properties are specified in two separate files. These “.mmp” and “.msp” files are generated by a separate python script. The permeability of the discrete fractures  $k=a^2/l^2$  (input for OGS) was calculated based on the aperture  $a$  (output from PFC2D) according to the cubic law assuming flow between two smooth parallel plates. The cross-sectional area  $A$  of each fracture was calculated based on aperture and vertical length  $l$  by  $A = l*a$ .



**Figure 1: General workflow to import data from the DEM simulator Particle Flow Code 2D (PFC2D) to the FEM code OpenGeoSys (OGS).**



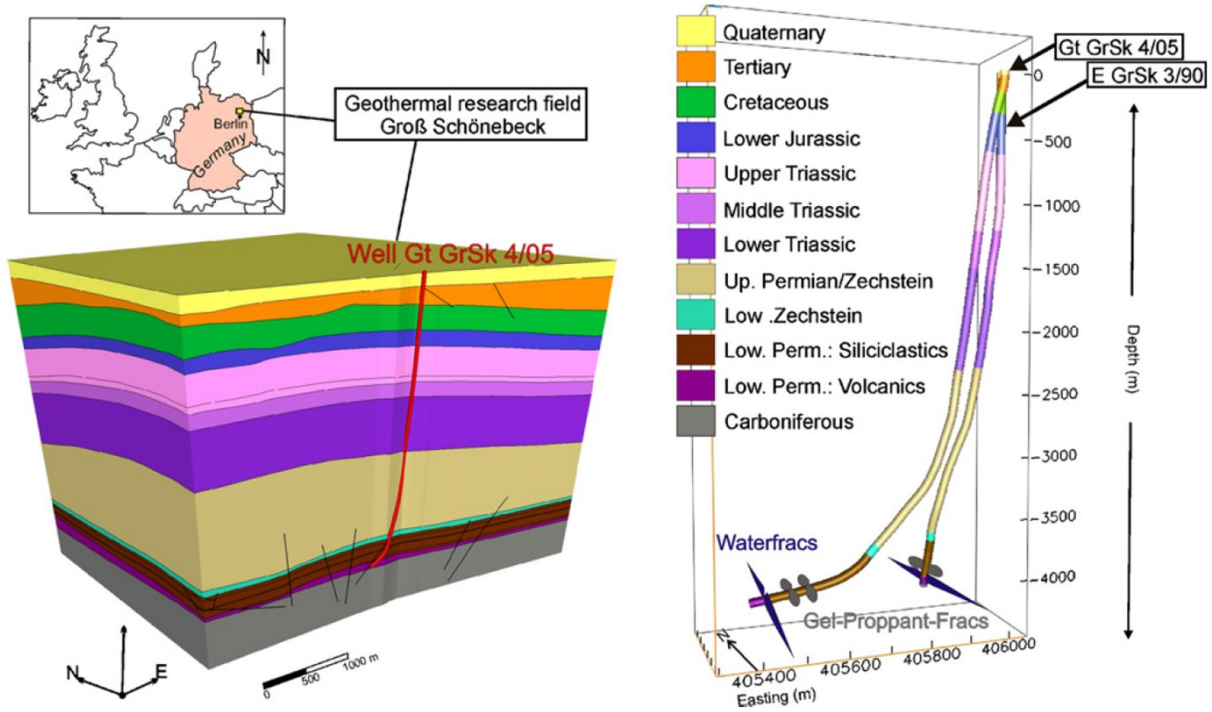
**Figure 2: In PFC2D fluid flows from one domain to adjacent domains, based on the pressure difference between them, along a direct line between two domain centers. A domain is the space between the balls which is confined by contacting balls. The geometry of these flow paths are extracted from PFC2D and a 2D FE mesh is generated around this geometry using an adapted version of the meshing software MeshIt (Blöcher et al., 2010) as the basis for the fluid flow and heat transport calculations in OpenGeoSys.**

## 4. EXEMPLARY FIELD APPLICATION: STIMULATION OF VOLCANIC ROCK LAYER IN GROSS SCHÖNEBECK

### 4.1 Model Description

The Groß Schönebeck EGS field laboratory is located about 40 km Northeast of Berlin in the North German Basin (**Figure 3**). The EGS currently consists of two wells (Gt GrSk 4/05 and E GrSk 3/90). Because the initial reservoir permeability was too low, both wells have been hydraulically stimulated by inducing gel-proppant fracs in the sandstone layer and one waterfrac in each well in the volcanic rocks (Zimmermann et al., 2009; Zimmermann et al., 2011). The productivities of both wells were initially increased but may be insufficient to run a power plant. Hence, an alternative stimulation strategy might need to be developed to additionally increase the flow rates through the system.

For this case study, only the volcanic rock layer is considered in 2D (with a constant thickness of 100 m; Blöcher, 2010) and two additional hypothetical wells are drilled (see **Figure 4** for their locations). Two questions will be answered by the hybrid simulation approach: (1) if one of the new wells is used for a pre-stimulation treatment to alter the initial in situ stress field, how would the stimulated fracture network look like? And (2) how would the thermal and hydraulic behavior (pressure and temperature evolution with time) change within the volcanic rocks after this stimulation treatment as compared to the behavior observed without the treatment? This exemplary application will show the benefits of the new hybrid modeling approach.



**Figure 3: Location, geological model, well paths, and hydraulic fractures of the Groß Schönebeck EGS research site (Zimmermann et al., 2010). From this model only the 100 m thick volcanic rock layer (Lower Perm) is simulated in 2D including the well GrSk 3/90 and the waterfrac in the volcanics.**

#### 4.1.1 DEM Model (PFC2D)

The DEM model is 3 km x 2 km in size (**Figure 4**) and oriented parallel to the direction of the maximum horizontal stress SH (108° azimuth; Blöcher et al., 2010). The model represents a 100 m thick section of the volcanic layer with strength properties of the volcanic rock (e.g. UCS, tensile strength, cohesion, friction angles) taken from Moeck et al. (2009), the hydraulic properties porosity and permeability taken from Blöcher et al. (2010), the in-situ stress field taken from Moeck et al. (2009) (all given in **Table 1**), and an initial in-situ joint network (shown in **Figure 5**). The 200, 20 – 60 m long, randomly-oriented pre-existing joints are located within the inner region of the model, which is packed with finer particles (**Figure 5**). In total, 56087 particles are used. The existing hydrofrac from well E GrSk3/90 is assumed to be 320 m long and extends parallel to SH (**Figure 4**). In the model it is represented by de-bonded parallel bonds (pipes) with an aperture of 22.8  $\mu\text{m}$  (Blöcher et al., 2010) assuming that it is opened in Mode I and propped. The location of these pipes is shown in **Figure 5**. With increasing normal stress  $\sigma_n$  the initial joint aperture  $a_0$  is reduced to an aperture  $a$  according to **Equation 1** with  $a_{\text{inf}}$  (=5  $\mu\text{m}$ ) being the minimum aperture at infinite normal stress and  $a_0$  (=22.5  $\mu\text{m}$ ) being the aperture at zero normal stress (Hökmark et al., 2010; Yoon et al., 2014). The injection point for the main hydraulic stimulation is located 500 m away from the well GrSk3/90. Prior to the main injection, a pre-stimulation treatment is performed in another injection point 250 m North-West of the main injection point (**Figure 4**).

$$a = a_{\text{inf}} + (a_0 - a_{\text{inf}}) \exp(-0.6\sigma_n) \quad (1)$$

**Table 1: Initial and boundary conditions applied to the DEM model of the volcanic rock layer in Groß Schönebeck.**

Initial/Boundary condition	Value	Remarks and References
SH' (effective max. horizontal stress)	52 MPa	SH' = SH - P = 95 - 43 = 52 MPa (Moeck et al., 2009)
Sh' (effective min. horizontal stress)	27 MPa	Sh' = Sh - P = 70 - 43 = 27 MPa (Moeck et al., 2009)
P (initial pore pressure at depth)	43 MPa	(Blöcher et al., 2010)
k (reservoir permeability)	9.9e-17 m <sup>2</sup>	Volcanic rock (unit IV) in Blöcher et al. (2010)
$\phi$ (reservoir porosity)	0.5 %	Volcanic rock (unit IV) in Blöcher et al. (2010)
H (layer thickness)	100 m	Volcanic rock (unit IV) in Blöcher et al. (2010)
T <sub>0</sub> (tensile strength)	5 MPa	1/20 of UCS estimate of 100 MPa (Moeck et al., 2009)
c (cohesion)	21 MPa	Moeck et al. (2009)
$\mu$ (coefficient of friction)	0.45	Moeck et al. (2009)
$\phi$ (friction angle)	25 °	Moeck et al. (2009)



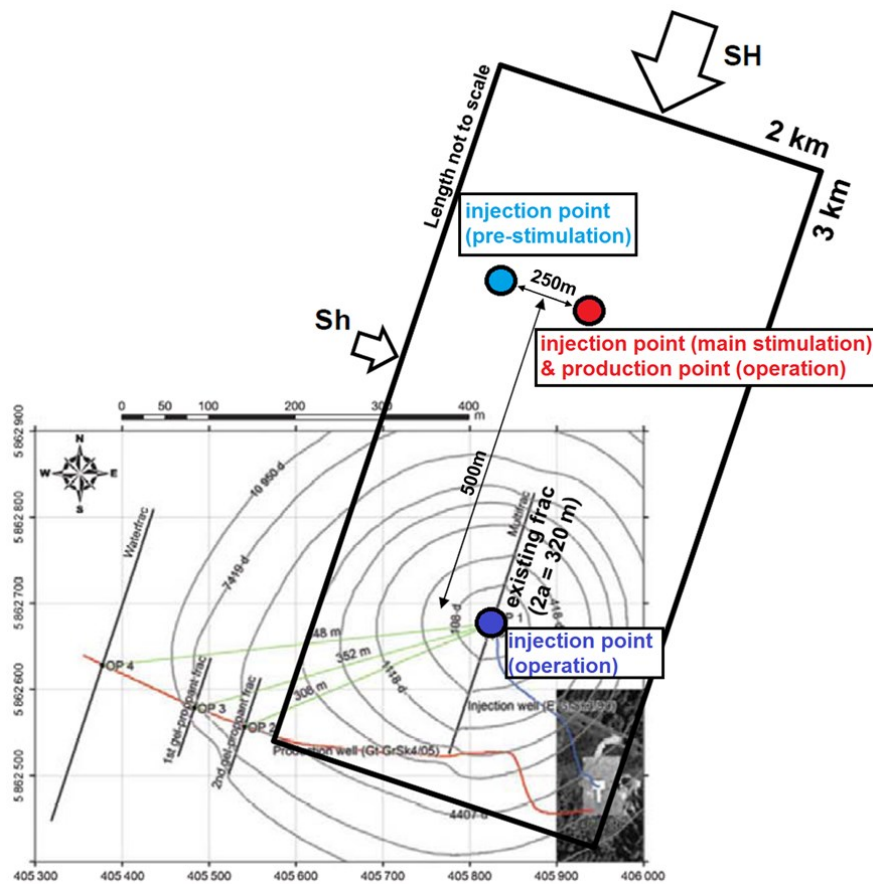


Figure 4: Model domain showing the positions of the injection points for the pre-stimulation treatment and the main stimulation. The red and blue lines are the existing wells GrSk 4/05 (red) and GrSk 3/90 (blue; adapted from Blöcher et al., 2010).

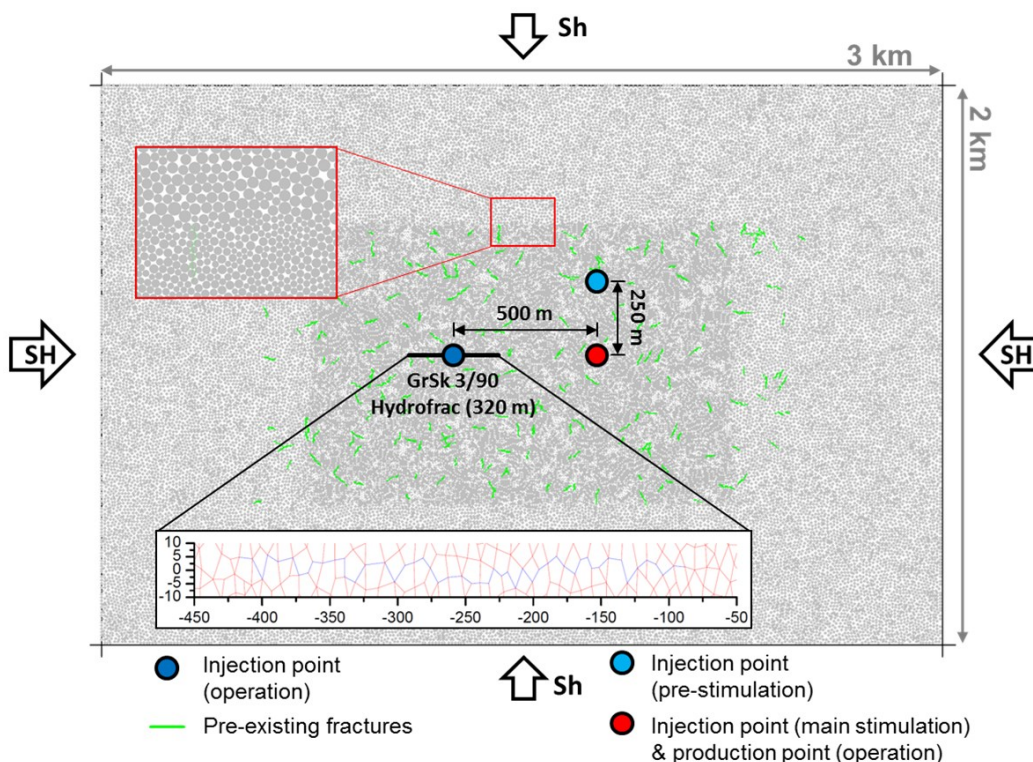


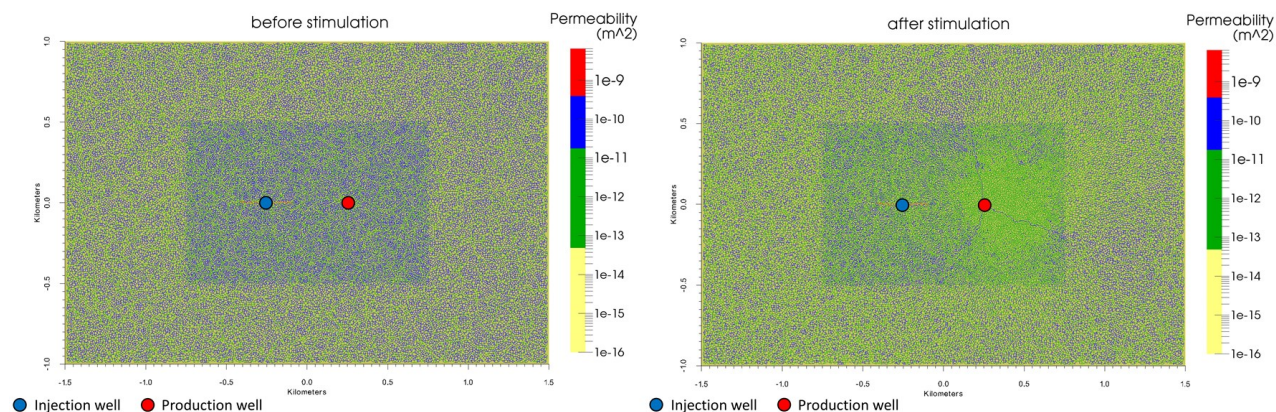
Figure 5: Bonded discrete particle model with randomly distributed and oriented pre-existing fractures representing the Groß Schönebeck volcanic rock layer. Particles in the center of the model are smaller. Additionally, the position of the high permeability initial hydraulic fracture, at the well GrSk 3/90 and the injection and production points for stimulation and operation are shown.

#### 4.1.2 FEM Model (OGS)

The FEM model dimensions are equivalent to the DEM model dimensions shown in **Figures 4 and 5**. The initial conditions were a homogeneous pressure of 43 MPa and a homogeneous temperature of 150 °C throughout the whole model domain. All four model boundaries were set to a constant pressure of 43 MPa. Among all other model specifications, the fluid, fracture, and matrix properties are given in **Table 2**. The model consists of 112613 discrete fractures (each with a different permeability), 206244 nodes, and 515103 elements (402486 triangles and 112617 lines) and the total simulation time is 30 years. Density, viscosity, heat capacity, and thermal conductivity of water changed as a function of temperature and pressure. The permeability distributions before and after the stimulation are shown in **Figure 6**. Even though in PFC2D there is no flow between the fractures the rock matrix permeability and porosity were set to  $9.9\text{e-}17\text{ m}^2$  and 0.5 % in the OGS model. If matrix porosity and permeability are set to zero the simulation results are very similar to the case shown here.

**Table 2: OpenGeoSys Setup File Specification of the 2D Reservoir Model**

Boundary conditions (.bc)	Value	Remarks and References
Temperature at injection well	70 °C	Blöcher et al. (2010) unit IV
Outer model boundaries	No flux	(adiabatic)
<b>Geometrical objects (.gli)</b>		
Point 0 production well	250, 0	New well that would need to be drilled
Point 1 injection well	-250, 0	In the center of pre-existing hydraulic fracture (well GrSk 3/90)
<b>Initial conditions (.ic)</b>		
Domain pressure	43 MPa	Blöcher et al. (2010) unit IV
Domain temperature	150 °C	Blöcher et al. (2010) unit IV
<b>Fluid properties (.mfp)</b>		
Density water	$f(P, T)$ kg/m <sup>3</sup>	Helmholtz free energy model
Viscosity water	$f(P, T)$ Pa s	IAPWS-2008 model
Heat capacity water	$f(P, T)$ J/kg/K	IAPWS-IF97 model
Thermal conductivity water	$f(P, T)$ W/m/K	IAPWS-2008 model
<b>Medium properties (.mmp)</b>		
Formation thickness/fracture area	100 m/f(a)	Blöcher et al. (2010) unit IV / $A = l \cdot a$
Matrix/fracture porosity	0.5/100 %	Blöcher et al. (2010) unit IV / open fracture
Matrix/fracture tortuosity	1/1	Assuming flow through parallel plates
Matrix/fracture storage	1e-10/4.6e-10	4.6e-10 compressibility of water
Matrix/fracture permeability	9.9e-17 m <sup>2</sup> /f(a)	Blöcher et al. (2010) unit IV / <b>Equation 1</b>
<b>Solid properties (.msp)</b>		
Matrix/fracture density	2650 kg/m <sup>3</sup>	Norden et al. (2008), for 20 °C
Matrix/fracture thermal expansion	7e-6 1/K	Avg. for Andesite (Lamond and Pielert, 2006)
Matrix/fracture heat capacity	981 J/kg/K	Norden et al. (2012)
Matrix/fracture thermal conductivity	2.025 W/m/K	at 150°C (Somerton, 1992; 2.3W/m/K at 20°C; Norden et al., 2008)
<b>Source terms (.st)</b>		
Injection well	20 l/s	Flow rate
Production well	-20 l/s	Flow rate
<b>Time discretization (.tim)</b>		
Minimum time step size	1 s	
Maximum time step size	1 year	
Total simulation time	30 years	



**Figure 6: Permeability distribution before (left) and after (right) the main hydraulic stimulation treatment.**

## 4.2 Modeling Workflow

### 4.2.1 DEM Model (PFC2D)

Prior to the main injection, a pre-stimulation treatment is performed to alter the initial in-situ stress field around the main injection point (i.e. from anisotropic to less anisotropic, which is favorable for fracture propagation deviating from SH direction). For the pre-stimulation treatment, 360 m<sup>3</sup> of water are injected at a constant rate of 10 l/s for 10 hours. The treatment starts with 5 cycles of 150 l/s in the first 25 hours. The idea behind using such a high injection rate of 150 l/s is to promote fractures propagation largely deviating from SH orientation by a pulse type injection. Also, 150 l/s is chosen as this rate has already been applied in Groß Schönebeck (Zimmermann et al., 2010).

### 4.2.2 FEM Model (OGS)

To evaluate the hydraulic and thermal behavior of the reservoir before and after the hydraulic stimulation treatment conducted in PFC2D, the fracture geometries and apertures before and after the treatment were converted into a FEM mesh and fracture permeabilities. Both models were run for 30 years with a production/injection rate of 20 l/s. Pressure and temperature field in the whole model domain and in the injection and production wells were observed to compare both cases. First, the pressure and temperature drawdown in the production well is compared over a period of 30 years. Additionally, the pressure buildup in the injection well is compared for both models. Finally, the impedance  $I$  (resistance of the formation to fluid flow) between injection and production well is calculated using the pressure at the injection well  $P_{in}$ , the outlet pressure at the production well  $P_{out}$ , and the production rate  $Q$  after 30 years of operation (**Equation 2**). A higher value of  $I$  indicates a higher resistance to flow. Hence, low values (usually below 0.1 MPa/l/s) are anticipated.

$$I = \frac{P_{in} - P_{out}}{Q} \quad (2)$$

Based on the impedance before and after the stimulation, the decrease in resistance of the formation to flow or the increase in productivity was calculated using **Equation 3**.  $FOI$  (Folds of Increase) is usually calculated based on the productivity index of one single well ( $PI_{after-stimulation}/PI_{before-stimulation}$ ); however, this value was adapted to evaluate the change in hydraulic performance of the whole reservoir between injection and production well. If the value of  $FOI$  is above 1, the impedance decreased (productivity and/or injectivity increased), if  $FOI$  is equal to 1 the impedance (productivity and/or injectivity) is the same after the treatment, and if  $FOI$  is below 1 the impedance increased (productivity or injectivity decreased) due to the stimulation treatment.

$$FOI = \frac{I_{before-stimulation}}{I_{after-stimulation}} \quad (3)$$

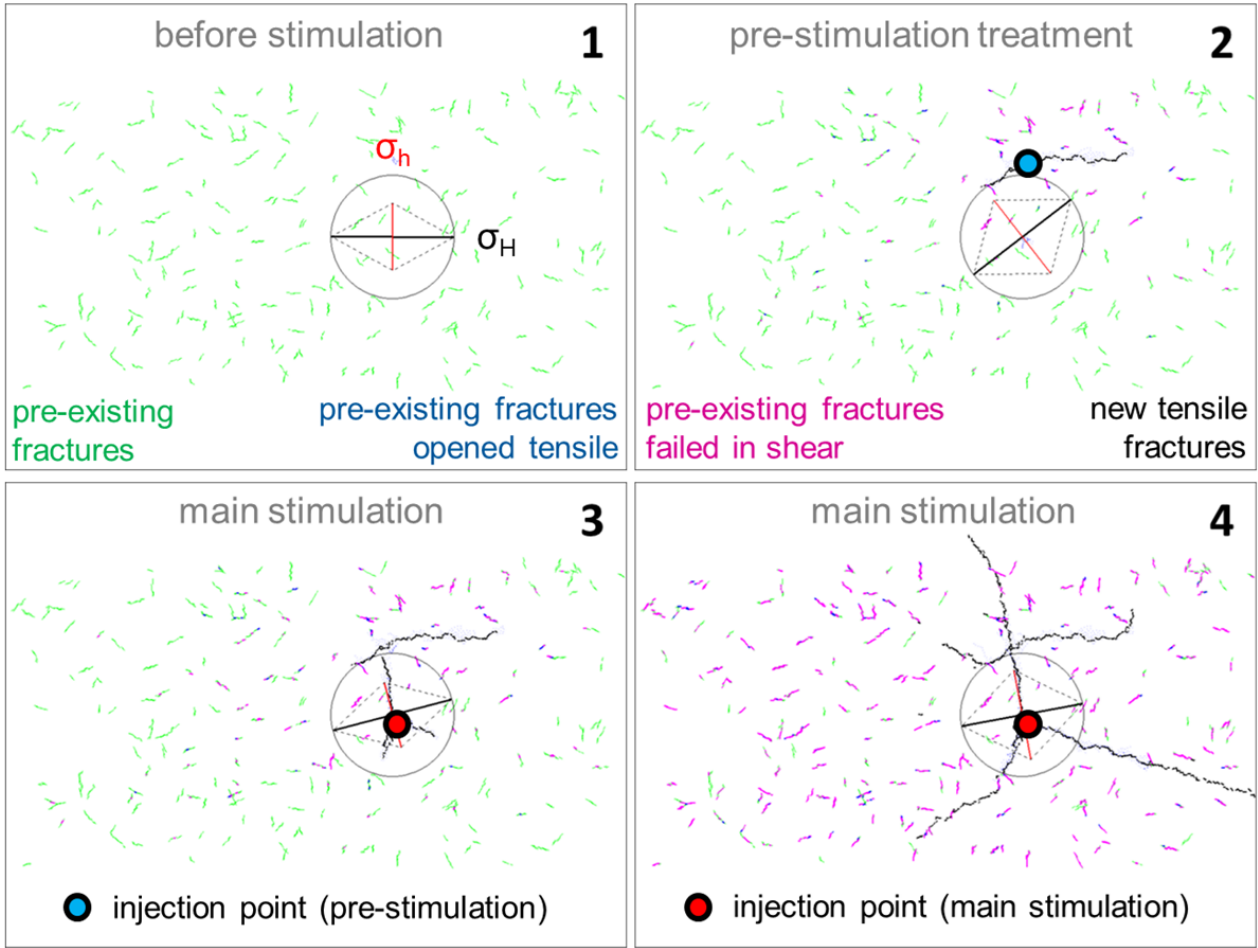
These values ( $I$  and  $FOI$ ) are independent on the flow rate and are used to evaluate the hydraulic efficiency of the stimulation treatment. By means of a comparison of production temperature development with time between the two models, the thermal efficiency of the hydraulic stimulation treatment is studied.

## 4.3 Simulation Results

### 4.3.1 DEM Model (PFC2D)

The pre-stimulation treatment performed 250 m northwest of the main injection well lead to the shear failure of natural fractures in the vicinity of the pre-stimulation injection point and an additional development of a tensile fracture growing parallel to SH orientation. Green segments shown in Figure 5 are the natural pre-existing fractures and their failure in Mode I and Mode II are denoted in blue and pink. The regional in situ stress field around the main injection point is described by the measurement circle logic in PFC2D. For the measurement circle, we chose its diameter to be 200 m and the orientations of the SH and Sh are denoted by the black and red lines normal to each other. Slenderness of the diamond shape by the dashed line indicates the ratio of the regionally monitored SH and Sh; i.e. the more slender the diamond is the greater the ratio of SH to Sh (higher stress anisotropy). Comparison of **Figures 7-1** and **7-2** shows that the pre-stimulation treatment altered the regional in situ stress field around the main injection point: (i) SH/Sh decreased to 1.3 (58.6/44.6) from 1.8 (52.5/28.6), (ii) SH orientation changes 37°. Such changes are due to stress shadowing effects. This change in the direction of SH due to the injected water was the purpose of the pre-treatment, which was hence successful.

After the regional in-situ stress field was changed by the pre-stimulation, the main stimulation treatment was conducted (**Figure 7-3&4**). Most of the pre-existing fractures failed in shear. Additionally, three major branches of tensile fractures were developed which line up locally with the pre-existing fracture network. This way it was possible to develop a diversified complex fracture network.



**Figure 7: Distribution of in-situ fractures (green), stimulated in-situ fractures (pink and blue), induced fractures (black), and orientation of maximum (black line) and minimum (red line) horizontal stress: 1 - before stimulation, 2 – at the end of the pre-stimulation treatment, 3 – during the main stimulation, and 4 – at the end of the main stimulation.**

4.3.2 FEM Model (OGS)

The FEM simulations are meant to evaluate the efficiency of the hydraulic stimulation treatment by comparing the thermal and hydraulic behavior of the reservoir before and after the treatment. **Figure 8** shows the pressure development in production and injection wells and the temperature development in the production well over the course of 30 years of continuous circulation at a rate of 20 l/s.

After approximately 15 years the temperature starts to decrease in the production well and drops slowly down to about 144 °C after 30 years if the injection well is not stimulated. If the injection well is stimulated the temperature drop is about 2 – 3 °C less (**Figure 8**). This is due to the different distribution of the cold fluid caused by the new fracture network (**Figure 9**). A visual comparison of the temperature development in the initial reservoir (left) and stimulated reservoir (right) after 30 years of operation shows a significantly different behavior of the temperature distribution that leads to the difference in the production temperatures (**Figure 9**). For the initial reservoir the cold water front is relatively circular with no preferential flow paths until it reaches the vicinity of the production well. In the stimulated reservoir, the cold water plume is distributed over a larger area in the vicinity of the production well because the water is flowing towards the newly developed fractures and from there towards the well.

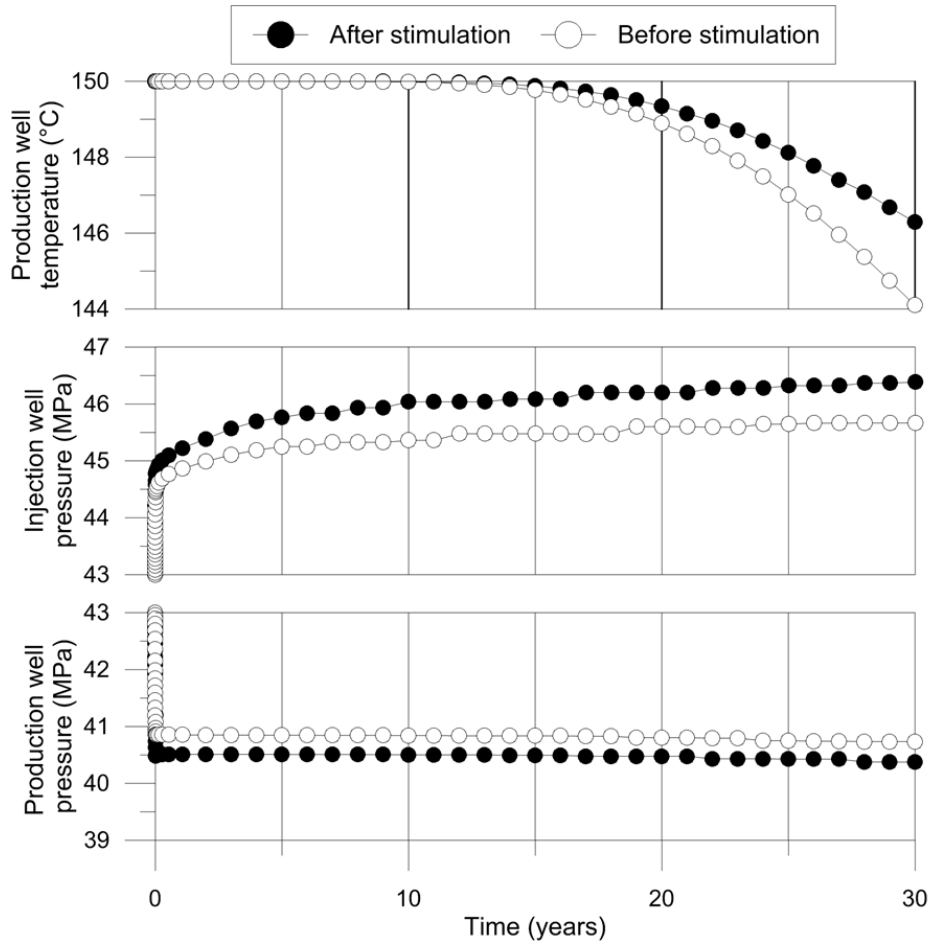
**Table 3: Flow Rate (Q), Inlet and Outlet Pressure (P<sub>in</sub> and P<sub>out</sub>) after 30 Years, Impedance before and after the Hydraulic Stimulation and Resulting Folds of Increase (FOI).**

	Before stimulation	After stimulation
<i>Q (l/s)</i>	20	20
<i>P<sub>in</sub> (MPa)</i>	45.7	46.4
<i>P<sub>out</sub> (MPa)</i>	40.7	40.4
<i>I (MPa/l/s)</i>	0.25	0.30
<i>FOI (-)</i>	0.82	

The injection pressure is slightly larger for the stimulated case due to the joint closure (and hence permeability reduction) in the vicinity of the injection well, which was caused by the stimulation (**Figure 6**). Pressure drawdown in the production well is also more significant for the stimulated case as compared to the initial reservoir conditions due to fracture closure caused by the

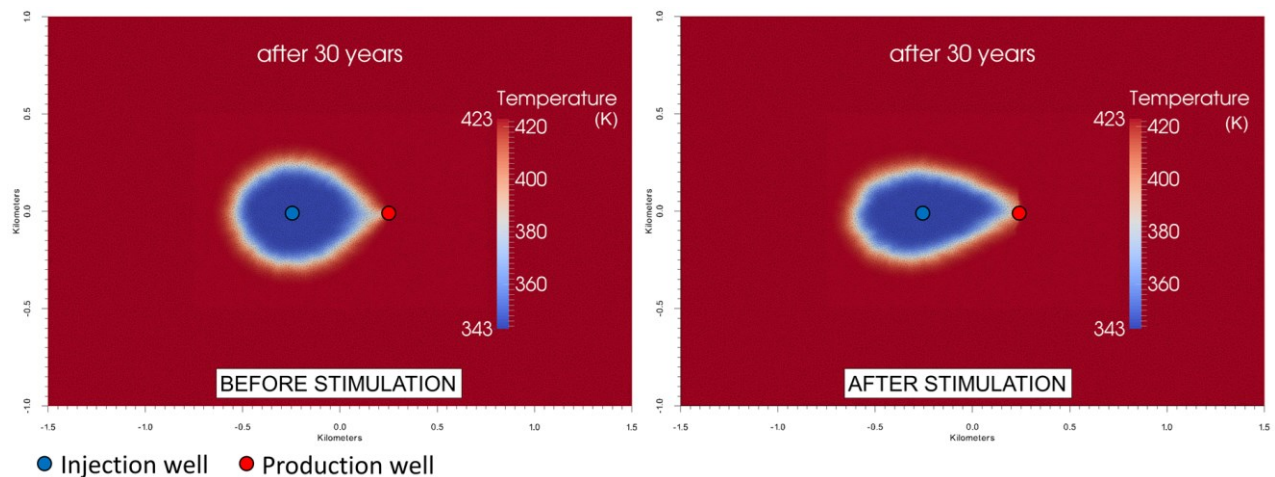


stimulation. The pressure drawdown in the production well is significantly less than the pressure buildup in the injection well because the viscosity of the produced hot water is significantly lower (0.2 mPas at 150 °C and 43 MPa) than the viscosity of the injected colder water (0.4 mPas at 70 °C and 43 MPa). After a short time, (in the order of a day) the production pressure reaches a constant level in both cases. But as the temperature starts dropping, the pressure drawdown increases due to the higher viscosity of the colder fluid produced by the production well.



**Figure 8: Pressure and temperature development in production and injection well during circulation (Scenario 1: before stimulation, Scenario 2: after stimulation).**

The resulting impedances given in **Table 3** also reflect this behavior and are compared to evaluate the hydraulic efficiency of the stimulation treatment. As the pressure data in **Figure 8** has already shown, the impedance, and thus the resistance of the reservoir to flow, is increasing slightly due to the stimulation treatment. Reasons for this unexpected behavior will be discussed in the next section.



**Figure 9: Reservoir temperature after 30 years of operation before the stimulation (left) and after the stimulation (right).**

## 5. DISCUSSION

The slower production temperature drawdown in the stimulated reservoir as compared to the initial reservoir conditions was expected because the new fracture branches did not grow towards the injection well but lead to a distribution of the cold water (**Figure 9**). However, it is unusual that the pressure drawdown and buildup in production and injection well is more pronounced in the stimulated case where less pressure drawdown and buildup are expected due to the improved fluid pathways. Looking at the permeability distribution of the flow channels before and after the treatment (**Figure 6**) explains this behavior. While three new high permeable fluid pathways were created around the production well, the change in the pressure and stress field caused by pre-stimulation and main stimulation led to a closure (and reduction of permeability) of most of the initial joints nearby the injection well, thus, decreasing its injectivity.

One reason for this increase in overall reservoir impedance might be a lack of a proper relationship between normal stress on a fracture and the resulting fracture aperture (**Equation 1**). This will be subject to further investigation. In any case, fracture closure due to stress shadowing effects might be an explanation for unsuccessful hydraulic stimulation treatments in heavily jointed rock masses. Additionally, this effect can potentially be used to avoid early thermal breakthrough by closing high permeable flow channels.

The influence of temperature on fluid viscosity and ultimately productivity was shown in this paper. The effect of mechanical opening and closure of fractures due to a pressure increase or decrease might be as important as the temperature dependent fluid viscosity and will be considered in future simulations. These effects will further change productivity and injectivity (or impedance) due to the opening and closure of fractures (and their resulting permeability increase or decrease).

Even though the numerical models are missing some important aspects of the real reservoir behavior (e.g. 3D structures and pressure dependent fracture conductivity during circulation), the results of the hybrid simulation approach reveal interesting insights into the hydraulic and thermal efficiency of complex hydraulic fracture networks. Additionally, both, PFC and OGS, have the ability to overcome these restrictions in the future.

The presented interface can be adapted to handle PFC3D output as well as output of other DEM codes such as UDEC/3DEC or alternative open source DEM models like ESyS-Particle (e.g. Wang, 2008).

## 6. CONCLUSIONS

Particle DEM simulators like PFC2D can simulate complex tensile and shear fracture development in an initially fractured rock mass but the hydraulic and thermal efficiency of these simulated fracture networks during EGS operation could not be evaluated up to now. The interface between PFC2D and OpenGeoSys makes it possible to model hydraulic stimulation treatments in heterogeneous and heavily jointed (> 100,000 individual fractures) reservoirs and to evaluate the efficiency of these treatments. It was found that for realistic simulation results, a proper relationship between normal stress and fracture aperture needs to be developed. The study of an example application of a hypothetical stimulation treatment in the volcanic rock layer at the Groß Schönebeck geothermal in-situ laboratory illustrates that the closure of pre-existing joint networks due to changes in the in-situ pressure and stress fields caused by a stimulation treatment can be one reason for unsuccessful hydraulic stimulation treatments in heavily jointed rock masses.

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