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1 **COUPLED THM MODELING OF HYDROSHEARING STIMULATION IN**
2 **TIGHT FRACTURED VOLCANIC ROCK**

3

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24 **ABSTRACT**

25 In this study, we use the TOUGH-FLAC simulator for coupled thermo-hydro-mechanical (THM)
26 modeling of well stimulation for an Enhanced Geothermal System (EGS) project. We analyze the
27 potential for injection-induced fracturing and reactivation of natural fractures in a porous
28 medium with associated permeability enhancement. Our analysis aims to understand how far the
29 EGS reservoir may grow and how the *hydroshearing* effect depends upon system conditions. We
30 analyze the enhanced reservoir, or hydrosheared zone, by studying the extent of the failure zone
31 using an elasto-plastic model, and accounting for permeability changes as a function of the
32 induced stresses. Results, for both fully saturated and unsaturated medium cases, demonstrate
33 how the EGS reservoir growth depends on the initial fluid phase, and how the reservoir extent
34 changes as a function of two critical parameters: the coefficient of friction and the permeability-
35 enhancing factor. Moreover, whereas the stimulation is driven by the pressure exceeding a
36 hydroshearing threshold, the modeling also demonstrates how the injection-induced cooling
37 boosts the stimulation a bit farther.

38 **INTRODUCTION**

39 Thermo-hydro-mechanical (THM) analysis is essential when dealing with energy extraction from
40 hot dry rock. The main concept of the Enhanced Geothermal System (EGS) is the exploitation of
41 high thermal gradient regions through the creation (or reactivation) of a fracture network by
42 increasing rock permeability, hence enhancing the circulation of water. EGS sites generally
43 feature very low permeability formation (such as igneous rock in volcanic regions), where cold
44 water is injected at moderate to high pressure to achieve *hydroshearing* (e.g., Cladouhos et al.,
45 2009). Contrary to the more common hydrofracturing (or simply *fracking*) process, during
46 hydroshearing reactivation, the injection pressure is kept below the minimum principal stress

47magnitude, causing existing fractures to dilate, slip and shear. Hydroshearing can permanently
48enhance permeability of natural fractures that conceptually should remain open because of self-
49propping of fractures due to surface roughness when the stimulation period ends and fluid
50pressure is reduced. As pointed out by Riahi and Damjanac (2013), the enhancement of the
51reservoir permeability during hydroshearing will depend on many *in situ* parameters, such as
52regional stress, geological, hydromechanical, and thermal parameters (e.g., frictional coefficient,
53intact rock permeability, heat capacity), as well as chemical processes associated with the
54injection of cold water.

55

56The concept of *hydroshearing* is not new, but was first recognized and developed in the early
571980s, when Pine and Batchelor (1984) confirmed that the creation of new fractures was not the
58dominant process during the injection of water into the rock mass at great depth. Far more
59important was the shearing of natural joints and, in particular, those aligned with the principal
60stresses of the local stress field. In this concept, the joints fail in shear because the fluid injection
61reduces the normal stress across them and allows frictional slippage to occur before jacking, or
62creating of new hydraulic fractures. This was first demonstrated for the Cornwall hot dry rock
63project in the Carnmenellis granite where injection was conducted at depths greater than 2 km
64below ground level. Microseismic events detected during the high-flow rate stimulations
65indicated strike-slip shear consistent with the orientation of the natural joints and in-situ stress
66conditions. Meanwhile, in the field rock mechanics, the effects of fracture shear on permeability
67was studied through laboratory and in situ block experiments, with the first comprehensive study
68conducted at the Norwegian Gestechnical Institute by Makurat et al., (1990). The concept of
69hydroshearing have since been employed at a number of EGS sites worldwide, including Hijoiro
70and Ogachi Japan as well as Soultz-sous-Forêts and Cooper Basin in Australia (Tester, 2006;

71Ziagos et al., 2013). Experience gained in the last thirty years at EGS field projects has shown
72the critical importance of understanding and mapping the natural fracture system and the in situ
73stress field (Evans et al., 1999, Tester 2006). Trans-tensional environments (e.g., grabens) may
74be more amenable to successful manipulation than compressive stress regimes in EGS reservoir
75creation (Baria et al., 1999). Moreover, in the recent few years a number of EGS demonstration
76projects have been launched in the U.S., in which different variants of hydroshearing is
77employed in stimulation and permeability enhancement of the reservoir (Ziagos et al., 2013).
78These are funded by the U.S. Department of Energy's Geothermal Technology Program and
79include EGS demonstrations at Desert Peak and Brady's Hot Springs, in Nevada, The Geysers in
80California, and finally the Newberry Volcano, Oregon (Ziagos et al. 2013). Three of these EGS
81demonstrations projects (Dessert Peak, Brady's, and The Geysers) are located within or on the
82margins of existing hydrothermal fields, whereas one (Newberry Volcano), is located at an
83unexplored and undeveloped site (Ziagos et al. 2013).

84

85In 2009, AltaRock Energy company was awarded a grant by the U.S. Geothermal Technology
86Program to plan and demonstrate an EGS at the Newberry Volcano, Oregon. During Phase I of
87the project, completed in April 2012, pre-stimulation field investigations were performed to
88understand the tectonic and volcanic setting, characterize the volume around the proposed EGS
89demonstration area, and plan the stimulation parameters. The stimulation plan was developed
90along the lines of Alta Rock Energy's approach to hydroshearing in which the rock is stimulated
91in stages by injection in multiple isolated sections of the well bore using a injection pressure that
92is slightly lower than the pressure required for hydrofracturing, i.e. slightly lower than the
93minimum principal stress (Cladouhos et al., 2009).

94

95A preliminary 3-D model of stress and fracture patterns was presented by Davatzes and Hickman
96(2011). Faulting is mainly evident along the caldera rim about 3 km from the designated
97injection well. There is no evidence of ring fractures or faults in the injection well (NWG 55-29)
98from drilling logs. Furthermore, Newberry Volcano has a very low seismicity rate (Cladouhos et
99al., 2013). An analysis of the natural fractures shows that there are two dominant sets that strike
100N-S and dip approximately 50° to the east and west (Davatzes and Hickman, 2011).

101The stimulation took place between October and December 2012, during which three zones were
102created by injecting thermal-degrading zonal isolation materials (chemical diverters) to isolate
103already stimulated zones (Petty et al., 2013). Over 40,000 m³ of water were injected in about 7
104weeks of stimulation, reaching a maximum well-head pressure of about 16 MPa with over 200
105induced microseismic events registered (Petty et al., 2013; Cladouhos et al., 2013). The
106maximum magnitude event (M_w = 2.39) was recorded during the period of highest well head
107pressure (P = 16.7 MPa). However, results show a strong correlation between the cumulative
108injected volume and cumulative logarithmic seismic moment, pressure does not correlate as
109strongly. The cloud of microearthquakes extends about 500–800 m from the injection well
110(Cladouhos et al., 2013).

111A simultaneous analysis of flow rates, pressure, and seismicity that occurred at the Newberry
112EGS Demonstration site after the stimulation shows that the injectivity increased after
113reactivation, indicating an increase in permeability. The maximum well-head pressure (controlled
114at pump) resulted only after the injection of the chemical diverters, which reduced the flow rates.
115Moreover, no changes in pressure or flow rate seem to indicate the occurrence of hydrofracking
116or tensile failure, meaning that the pressure was below the minimum principal stress, but well
117within the range to achieve hydroshearing and its associated permeability enhancement.

118

119 Starting from the results obtained at Newberry Volcano, here we aim to study the hydroshearing
120 effects during stimulation at an EGS site. We use as input the same stress field and rock
121 properties (such as low permeability and porosity) measured at Newberry, and simulate the
122 stimulation using a transient well-head pressure similar to the one recorded on the field. We do
123 not aim to reproduce neither the seismicity nor the flow rate in exact detail, but aimed at a model
124 that broadly represent the conditions and injection data at the Newberry. For example, we used a
125 simplified but representative well pressure and a resulting flow rate that was similar to the
126 measured one, though not matched in great detail.

127

128 The main goal of this work is to understand how hydroshearing may occur during stimulation,
129 using the Alta Rock's hydroshearing approach (Claduohus et al., 2009). Through the use of the
130 simulator TOUGH-FLAC (Rutqvist et al., 2002), we simulate a porous medium, which deforms
131 when subjected to stress change. Fracture effect is simulated by assuming an anisotropic field of
132 permeability, with the most of the fluid flow occurring then along the assumed fracture direction.
133 Generally fracture aperture may change as subject to stress, and we simulate such a process by a
134 permeability-stress relation. Furthermore, if the stresses reach a critical value, defined by the
135 Mohr-Coulomb criterion, shear failure will occur, and the permeability of the porous medium
136 will be further enhanced by a certain factor (generally between 2 and 3 orders of magnitude –
137 Rutqvist and Stephansson, 2003). We study the extent of the EGS reservoir after the stimulation
138 (hydrosheared zone) both in a single-phase (liquid), single-component (water) system and in a
139 two-phase (gas, liquid), two-component (CO₂, water) system. Effects of some key parameters,
140 such as the frictional coefficient and a permeability-enhancing factor, are studied as well.

141 **MODEL SETUP**

142 The coupled THM analysis was conducted using the simulator TOUGH-FLAC (Rutqvist et al.,
143 2002; Rutqvist, 2011) based on the geothermal reservoir simulator TOUGH2 (Pruess et al.,
144 2011), which allows the modeling of multiphase and multicomponent fluids in a porous medium,
145 and the geomechanical code FLAC3D (Itasca, 2009), for the stress changes induced by pressure
146 and temperature. The TOUGH-FLAC simulator has been recently applied and tested over a wide
147 range of research fields, such as carbon sequestration (e.g., Cappa and Rutqvist, 2012; Rinaldi
148 and Rutqvist, 2013), nuclear waste disposal (e.g., Rutqvist and Tsang, 2012, and references
149 therein), hydrothermal systems and volcanology (Todesco et al., 2004), as well as studies related
150 to water injection in geothermal fields (e.g., Rutqvist et al., 2013a; Vasco et al., 2013).

151 Following the approach of Rutqvist et al. (2013a) for modeling of the stimulation injection at the
152 Northwest Geysers EGS Demonstration Project, we studied the stimulation at a generic EGS
153 reservoir with low initial permeability, suitable for observing hydroshearing, such as at Newberry
154 Volcano. Although it is beyond the aim of this paper to reproduce the data and observation
155 recorded at the Newberry EGS Demonstration, we preferred to perform our simulation study of
156 the hydroshearing and EGS reservoir extent starting from some reliable parameters such as those
157 obtained from Newberry Volcano site, where data were collected for more than one year before
158 starting the stimulation. In this study, we extended Rutqvist et al.'s (2013a) approach to calculate
159 the actual permeability enhancement during the injection.

160 We considered a one-quarter symmetric model, with the injection well (corresponding to the
161 Newberry well NWG 55-29) located in one corner (Fig. 1). The model domain is a parallelepiped
162 of dimensions $1.5 \times 1.5 \times 3.5$ km and consists of four layers, representing the main geological
163 formations of the Newberry area (Sonnenthal et al., 2012). Hydrological properties are listed in
164 Table 1.

165 During hydroshearing and hydrofracturing, the medium permeability changes as a result of
 166 injection-induced fluid pressure and effective stress changes, and is strongly dependent on *in situ*
 167 stress magnitude and orientation as well as fracture orientation. In this study, we consider a
 168 stress-dependent permeability (hence also an anisotropic initial permeability) with maximum
 169 permeability in the NS-direction, in order to simulate a highly fractured low permeability
 170 formation (such as the intruded John Day formation at the Newberry volcano).
 171 The injection well was simulated as a porous medium with high vertical permeability and very
 172 high porosity). It is divided into two sections. The first section represents a cased well (high
 173 vertical permeability and very low horizontal permeability), which allow heat exchange only and
 174 prevent fluid escaping from the well to the host rock. The second section represents an open well
 175 completion (very high vertical permeability and same horizontal permeability as the host rock)
 176 that allows the injection of cold water into the highly fractured low permeability formation
 177 (between 2000 m and 3000 m depth).
 178 Initial temperature and pressure distribution were extracted from former analyses of the pre-
 179 stimulation steady-state conditions at Newberry Volcano (Sonnenthal et al., 2012). The
 180 temperature follows a high gradient of about 100 °C/km, with a maximum temperature of about
 181 360°C at the bottom of the domain. The pressure is slightly lower than hydrostatic, with a linear
 182 gradient of about 8.3 MPa/km. Constant pressure was set at the top and bottom boundaries,
 183 whereas side boundaries were assumed to be closed to fluid flow. No-flow side boundaries are
 184 needed to simulate only a quarter of a symmetric domain.
 185 Mechanical properties follow the results of Li et al. (2012). We chose to simulate a model with
 186 homogeneous mechanical properties and use a Young's modulus of $E = 15$ GPa and Poisson's
 187 ratio $\nu = 0.3$. Homogeneous mechanical properties should be adequate in this case, since we
 188 simulate a short-term stimulation (slightly less than two months) that should affect only the

189 injection zone (EGS reservoir). Indeed mechanical properties (such as shear and bulk modulus,
 190 and friction angle) may depend on medium heterogeneities, and then affect the stress and
 191 deformation distribution at macro scale. However, we are already accounting for an anisotropic
 192 permeability field, which affect the pore pressure distribution, and then the stress evolution as
 193 well. Random heterogeneities in mechanical properties may be present in a real field, but only at
 194 microscopic scale (i.e. too small to be analyzed in this study).

195 Initial geomechanical conditions follow those used by Cladouhos et al. (2011) for the pre-
 196 stimulation analysis performed with the AltaStim simulator. We considered a vertical stress
 197 gradient of 24.1 MPa/km (σ_v , maximum principal stress in z-direction). The intermediate
 198 principal stress is oriented in the NS-direction (y-axis, σ_H) with a gradient of 23.5 MPa/km.
 199 Finally, the minimum principal stress is oriented in the EW-direction with a gradient of 14.9
 200 MPa/km (σ_h , x-axis). Thermal effects on stress were taken into account as well, choosing a
 201 coefficient of linear thermal expansion $\alpha_t = 10^{-5} \text{ }^\circ\text{C}^{-1}$.

202 **Permeability changes**

203 Laboratory tests have shown how the state of stress may affect the hydraulic properties in
 204 samples (e.g. Liu et al., 2004). Specifically, the medium permeability is related to the fracture
 205 mechanical aperture b and to the effective stress normal to the fracture σ_n according to the
 206 following exponential function (Liu et al., 2004):

$$207 \quad b = b_r + b_{\max} \exp(\alpha \sigma_n) \quad (1)$$

208 where b_r is the initial mechanical aperture, $b_{\max}$ is the mechanical aperture corresponding to zero
 209 normal stress, α is a parameter related to the curvature of the fitting function. The mechanical
 210 aperture change can also be simply related to the initial state of stress (Rutqvist et al., 2008):

$$211 \quad b = b_i + b_{\max} (\exp(\alpha \sigma_n) - \exp(\alpha \sigma_i)) \quad (2)$$

212, and σ_{ni} is the initial stress normal to the fractures. In our formulation, compressive stresses are
 213 considered negative.

214

215 Generally most of the EGS sites feature a fracture system striking a certain direction. The
 216 Newberry Volcano, for example, features a NS-striking fracture system. Such a direction would
 217 be the y-axis in our formulation, and by assuming an initial anisotropic permeability field in a
 218 porous medium (higher permeability on y-axis), we can simulate the effects of the fracture
 219 network. The permeability would change mostly in the fracture direction (i.e. y-axis) and
 220 changes will be negligible in the other directions. We can calculate the changes in permeability
 221 along the y-direction (κ_y) as a function of the normal stress (σ_x) using the cubic law of parallel-
 222 plate flow (Witherspoon et al., 1980):

$$223 \quad \kappa_y = f \frac{b_y^3}{12} \quad (3)$$

224 where κ_y is the permeability in the fracture direction (y-axis in our case) and f is the fracture
 225 spacing. b_y is the fracture aperture from Eq. 1 or 2, and it is a function of the stress normal to the
 226 fracture (σ_x).

227 Using the approach described by Eqs. 1-3 would require a high number of unknown parameters
 228 that need to be calibrated (b_r or b_i , b_{max} , f , and κ). However, we can reduce the number of
 229 parameters by following an approach for scaling the fracture properties with the initial
 230 permeability (Liu et al., 2004). Following Eq. 3, we can relate the ratio between initial,
 231 unstressed permeability and the final permeability to the ratio between the aperture at initial state
 232 and aperture at final stage:

$$233 \quad \frac{\kappa_y}{\kappa_{yi}} = \left(\frac{b_y}{b_{yi}} \right)^3 \quad (4)$$

then using a dimensionless parameter $R_b = b_r/b_{\max}$, and combining Eq. 4 with Eq. 1, we can write for permeability changes (Liu et al., 2004):

$$\frac{\kappa_y}{\kappa_{yi}} = \left[\frac{R_b + \exp(\alpha \sigma_x)}{R_b + \exp(\alpha \sigma_{xi})} \right] \quad (5)$$

where the stress aperture function is related to the dimensionless parameter $R_b = b_r/b_{\max}$. Assuming the fractures to be identical, R_b will be a constant through the model domain. Using R_b , the permeability change factor is independent of initial permeability. We implemented Eq. 5 into TOUGH-FLAC and calibrate our model for two parameters only (R_b and α) using data recorded during an injection test (see following section).

The variation of stress is not the only process that may affect the permeability. Most of the changes will occur after shear reactivation, which is the main mechanism for creating permanent permeability enhancement within the EGS reservoir. However, while stress-induced permeability changes occur everywhere in the domain along the direction of fractures subjected to aperture changes, the shear-induced permeability changes only occur in the portion of the domain subjected to shear reactivation. In this work we assumed that the permeability would change by a fixed factor if a gridblock were subjected to shear reactivation:

$$\kappa_i = K_{HS} \cdot \kappa_i^{bHS} \quad (6)$$

for the i -direction. K_{HS} is a constant value (set to 500 for the base case analyses, i.e., between 2 and 3 orders of magnitude), and the index bHS refers to the permeability before the hydroshearing. Reactivation may occur with random orientation if a threshold pressure is reached, then we cannot attribute the changes in a single direction, but we assume the permeability changes isotropically if shear reactivation occur.

256 In case of multi-stage shearing, the permeability changes accordingly, i.e. the permeability $\square^{bHS}$
257 represents the one before the actual shear stage.

258 A similar approach was also recently used by Kelkar et al. (2012) during the study of shear
259 stimulation at Desert Peak Geothermal Field (Nevada), though limiting the permeability change
260 to a factor of 15 upon shear failure.

261

262 Alternative approaches for modeling hydroshear may involve discrete fracture network models
263 or combinations of fracture network and continuum models. For example when using the distinct
264 element codes 3DEC or UDEC in which each fracture is explicitly represented, the permeability
265 changes in individual rock fractures may be calculated as a result of aperture changes due to
266 shear induced dilation based on some constitutive law for single fractures (e.g. Min et al. 2004).
267 Other examples involve discrete fracture network models originally developed for groundwater
268 flow and transport extended through a simplified geomechanics approach in which shear failure
269 on each fracture is evaluated in an assumed and constant and homogenous external stress field
270 (e.g. Willis-Richards 1996; Bruehl, 2007). In such an approach, the fracture responses upon shear
271 failure may be calculated based on a local elastic solution for an assumed circular shaped
272 fracture of certain radius. For example, based on the radius of the fracture and shear modulus of
273 the surrounding rocks, the shear stress drop and maximum shear displacement and associated
274 fracture dilation and permeability change can be calculated. Such an approach has the potential
275 of handling a large number of fractures explicitly, but the mechanics is simplified as described
276 and does not consider shear induced stress changes or relaxation of the stress field in stimulated
277 areas. A combination approach may involve considering a back-ground fracture network used for
278 calculating equivalent continuum properties that for a very fine continuum mesh can be used to
279 represent fractures explicitly by changing properties of elements that are intersected by

individual fractures surfaces (Tezuka et al., 2005; Rutqvist et al., 2013b). The approach for permeability change adopted in this study can be considered a rational approach applied to a continuum model. However, regardless of the model adopted it usually involves some level of calibration against field data as will be discussed in the next section.

284

285 **Model calibration**

Model calibration is necessary for understanding whether the system is correctly responding to the injection of fluids and whether boundary and initial conditions are properly set.

Pore compressibility (c_p) and thermal conductivity (λ) within the injection well were calibrated to match field data. Moreover, a calibration is needed to assign appropriate values to the parameters α and R_b for the stress-dependent permeability function (Eq. 5).

The calibration was made simulating a low-pressure injection test, and comparing the resulting pressure and temperature profiles along the well with data collected at the NWG 55-29 well during a field injection test (September-October 2010).

According to Davatzes and Hickman (2011) the injection test was performed in two steps.

During the first period, lasting three days, the injection rate was 0.6 L/s (10 gpm) with an injection temperature of 10°C and a well-head pressure of about 5 MPa (750 psi). This period was then followed by two weeks of shut-in, before restarting the injection for nine days at a rate of 1.4 L/s (22 gpm), with an injection temperature of 10°C and a wellhead pressure of about 8 MPa (1153 psi).

Here we performed a simulation with the same, transient injection and we reproduced the same observed profiles along the well for pressure and temperature after 3 days at 10 gpm (Fig. 2a and 2b for pressure and temperature, respectively) and after 9 days at 22 gpm (Fig. 2c and d, for pressure and temperature, respectively), considering the permeability changes that may arise

304with the evolving effective stresses. Parameters for permeability changes were set constant
305during the two stages as $R_b = 0.2$ and $\beta = 0.13 \text{ MPa}^{-1}$ after calibration (see Eq. 5). The calibration
306for R_b and β is not unique, but the used of the two parameters only reduce the degree of freedom
307of the system.

308The pore compressibility and thermal conductivity were calibrated as well, and the values
309allowing a good match between simulated and measured profiles are listed in Table 1. As stated
310by Davatzes and Hickman (2011), after nine days of 22 gpm injection the well-head pressure was
311lowered to allow the well to be logged; hence, the pressure field data in Figure 2d needs to be
312recalibrated to match a wellhead pressure of 8 MPa (1153 psi) during the majority of the inject-
313to-cool operation.

314 **STIMULATION AND HYDROSHEARING MODELING**

315The stimulation of an EGS reservoir requires that an elevated amount of water be injected into
316the system. For example, at the Basel geothermal system (Switzerland) more than 11500 m³ of
317water were injected in about 5 days (about 30 L/s average flow rate) before peaking at a well-
318head pressure of almost 30 MPa and inducing a $M_L = 3.4$ event (Bachmann et al., 2011). In
319contrast, at the Northwest Geysers EGS Demonstration at The Geysers Geothermal Field
320(California), flow rates reached more than 50 L/s, but bottom-hole pressures were relatively low
321(typically less than 8 MPa), resulting in a large number of small-magnitude seismic events and a
322maximum magnitude event of 2.87 (Garcia et al., 2012; Vasco et al., 2013; Rutqvist et al. 2013a).
323Flow rates during the stimulation at the Newberry EGS Demonstration ranged from about 5 L/s
324up to 20 L/s, with a well-head pressure that peaked at about 16 MPa (Fig. 3, Petty et al., 2013).
325The stimulation was conducted in three different stages, and thermally degradable zonal isolation
326materials (TZIM) were injected between each stage to partially seal stimulated permeable

fractures and activate stimulation in a new zone. The use of chemical diverters (TZIM) helped to stimulate multiple zones in the well bore, resulting then in a more injection or flow capacity (last ten days in Fig. 3). Detailed description of the three stages performed during the stimulation can be found in Petty et al. (2013).

Here we are interested in the effects of the stimulation on hydroshearing and how far EGS reservoirs can extend under different system conditions. In most of the EGS applications, operators try to maintain a fixed injection rate, monitoring the injection pressure as outcome. However, we preferred to keep the pressure constant rather the injection rate, since the pressure is the main variable for reactivation. There was no fundamental reason, and it was done for better understanding of the process of hydroshearing, which is mainly based on pressure rather than on the flow rate. The stimulation injection is simulated by fixing the pressure at the top of the well, following the average values recorded at the Newberry Volcano EGS Demonstration. Again, it is not our goal to reproduce the observed injectivity and flow rates in detail, but it is essential to keep our model as close as possible to a real case, in order to achieve reasonable simulation results (Fig. 3).

We simulated the injection in two stages. The first stage lasted for about 28 days with a fixed well-head pressure of 7.8 MPa. This is followed by a 10 day shut-in period, before the injection restarts for the second stage with 3 days at 7 MPa and 10 days at 14 MPa (Fig. 3, green line). Note that we did not consider the effect of diverters (TZIM), which means that an increase in pressure results in an increase in flow rate, whereas, as observed at Newberry, the diverters sealed the permeable zones, permitting an higher well-head pressure without a substantial increase in flow rate prior to the start of subsequent stimulation steps.

The increase in pressure is necessary to allow the system to reduce the shear strength of fractures to less than the shear stress across the fracture, and enable the hydroshearing of fractures with a

351wider variety of fracture orientations to occur (Cladouhos et al, 2011). Rather than keeping a
 352fixed, high value for the well-head pressure, we preferred to study a case of transient evolution,
 353in which the injection starts at a relatively low pressure (7 MPa, first stage) and then is doubled
 354after a shut-in (no-injection) period (14 MPa, second stage). The values we chose are within the
 355range needed for hydroshearing, but never exceeded the minimum principal stress, so that only
 356shear failure can occur, rather than tensile failure or fracturing.

357To estimate the extent of the EGS reservoir, we looked at the zone where the system is subjected
 358to hydroshearing. This can be done with a Mohr-Coulomb model: considering a cohesionless
 359solid, shear reactivation will occur when the following criterion is satisfied:

$$360 \quad \sigma'_{1c} = N_{\phi} \sigma'_3, N_{\phi} = \frac{1 + \sin \phi}{1 - \sin \phi} \quad (7)$$

361where σ'_{1c} is the critical maximum principal effective stress (σ'_{vv} or σ'_{zz} in our case), and σ'_3 is the
 362minimum principal effective stress (σ'_{hh} or σ'_{xx}). ϕ is the frictional angle (frictional coefficient
 363 $\mu = \tan \phi$), which is set to 30° for the base-case simulation. In our model we considered as Mohr-
 364Coulomb solid the Intruded John Day formation only, and the upper John Day formation, which
 365is not a highly fractured formation, acts as a barrier for fracture propagation (Fig. 1). This may
 366not be true in the field, and the fractures may propagate to shallow depth.

367Equation 7 corresponds to the case in which the media contains fractures with a uniform
 368distribution of orientations and equally spaced throughout the reservoir. Using this approach,
 369shear reactivation would be induced whenever the maximum principal stress is N_{ϕ} times higher
 370than the minimum principal stress.

371 **Stimulation of a single phase, single component system**

372The first model we analyze does not take into account the presence of gas within the system.
 373Basically, we simulated the stimulation of a geothermal system injecting water into a fully water-

374saturated system. We are fully aware that this is a limiting case in this high temperature
 375environment, but would certainly be applicable in lower temperature systems. For this base case
 376the friction angle ϕ was set to 30° , i.e., a standard value corresponding to a frictional coefficient
 377of about 0.6. The constant K_{HS} for shear-enhanced permeability changes was set to 500, i.e.
 378corresponding to a 2.7-order magnitude change in permeability to all directions when a shear
 379reactivation occurs. This constant was set to a sensible value (Rutqvist and Stephansson, 2003).
 380For example, Lee and Cho (2002) have shown after laboratory tests that two orders magnitude
 381increase in fracture permeability may arise upon shear displacement.

382Figure 4a shows the pressure transient evolution applied at the top of the injection well (red line)
 383and the resulting flow rate associated with the water-saturated system (blue line). Results show a
 384first period during which the flow rate increases up to about 30 kg/s, then hydroshearing begins
 385occurring and the flow rate stabilizes to a constant value of about 20 kg/s (or L/s) for the rest of
 386the first stage (0 – 28 days with well-head pressure at 7.8 MPa). During the 10 day shut-in
 387period, the flow rate is almost nil. Then, during the second stage of stimulation, the well-head
 388pressure reaches 14 MPa, and the flow rate peaks at more than 60 kg/s, only to decrease to 40
 389kg/s at the end of the stimulation. The simulated flow rates are similar to values observed at EGS
 390demonstration sites such as The Geysers (Rutqvist et al., 2013a; Vasco et al., 2013) and
 391Newberry Volcano (Petty et al., 2013). Again, note that we are not simulating any injection of
 392diverters, and then, during our second stage of the stimulation for a higher well-head pressure,
 393we achieve a higher flow rate. The use of diverters proved to be effective at Newberry, where the
 394sealing properties of the injected isolating materials sealed the existing permeable fracture
 395network, thus resulting in higher pressures but with the same flow rate (Petty et al., 2013).
 396Results for pressure changes within the system, and the resulting zone affected by shear
 397reactivation after 28 days of stimulation, are shown in Figure 4b and c, respectively. Pressure

changes and the hydrosheared zone both extend up to about 400 m from the injection well in the NS direction (y-axis), i.e., along the direction we set as the primary fracture strike, which has higher permeability (Table 1). Growth of the hydrosheared zone is much smaller in the EW direction (x-axis), since both the initial permeability and the stress-induced permeability changes are smaller in the EW direction, which means that pressure changes do not propagate much in that direction. Although the pressurization within the well reaches about 8 MPa (same as the wellhead pressure during this first stage), within the system the pressure changes are a few MPa smaller, reaching a maximum of 6 MPa at the bottom of the well (Fig. 4b). However, these few MPa changes are enough to satisfy the failure criterion and activate the shearing process (Fig. 4c).

After the second stage, the increased well-head pressure results in higher-pressure changes within the system. In fact, Figure 4d shows the changes to be around 6 MPa, with maximum value of 8 MPa in the region close to the bottom of the well, although these values are still a little smaller than the pressure change within the well (about 12 MPa). The resulting hydrosheared region expands somewhat during the second stage, reaching a maximum value of about 500 m along the NS-direction (Fig. 4e). We can estimate the extent of the EGS reservoir and calculate the volume of the region affected by pressure change and where reactivation occurred: such a stimulated volume corresponds to about $9 \cdot 10^7 \text{ m}^3$, i.e., about 0.1 km^3 .

Stimulation of a two phase, two component system

In this section, we consider a system that before the stimulation is completely dry, saturated with gaseous CO_2 , subjected to cold-water injection. Hydrological and mechanical properties were kept the same as the fully water-saturated case. We used an equation of state for a two-components system (CO_2 and water – EOS2). Carbon dioxide can dissolve in water according to the Henry's law and the equation of state is applicable up to the water critical temperature (350

422°C), although it does not account for chemical reaction. More details can be found elsewhere
423(Pruess et al., 2011).

424This conceptual model may be somewhat unrealistic, but it represents a good case study as
425compared to the previous water-saturated system. Moreover, CO₂ is a good approximation for a
426volcanic gas: there are a few examples in literature of CO₂ degassing in volcanic regions, such as
427Campi Flegrei caldera (Italy) (e.g. Todesco et al., 2004) or Furnas (Azores) (e.g. Rinaldi et al.,
4282012). As previously implemented, we set the friction angle to 30° and the shear-enhanced
429permeability-changes factor to 500.

430Results of the stimulation for this system involving two fluid phases and two fluid components
431are shown in Figure 5. The pressure transient evolution imposed at the well is the same as
432previously (red line, Fig. 5a), and only a few changes are evident in the resulting flow rate
433compared to the case of a water-saturated system (blue line, Fig. 4a and 5a). The small variations
434are at the beginning of the simulation, during which a system with gas requires a higher flow rate
435to displace the gas from the region close to the injection well.

436The resulting pressure increase after the first stage (28 days) is still close to the injection well,
437with an average value of about 5 MPa (Fig. 5c). Although the pressure changes do not propagate
438far from the injection well, the average variation is still similar to the previous water-saturated
439case (Fig. 4b). As a consequence of the poorly distributed pressure changes, at this stage the
440region affected by hydroshearing is limited to a small region around the injection well and
441extends only for about 60 m along NS direction and 13 m along EW direction (Fig. 5d).

442After the second stage (51 days), the pressure changes are still averaging around 5 MPa,
443although within the well the pressure is 14 MPa (Fig. 5d). In any case, at this stage the pressure
444perturbation propagated more, resulting in a larger region where the shear reactivation occurred.

445The hydrosheared region extends about 100 m along the NS direction and about 25.5 m along the
446EW direction (i.e., almost twice that after the first stage, Fig. 5e).

447The results suggest that fractures will propagate much less in a medium initially saturated with a
448compressible gas. In fact, the stimulated volume resulting for an unsaturated medium is about
449 10^7 m^3 , i.e., about 1 order magnitude smaller than the volume that can be stimulated in a medium
450fully saturated with water. This effect can be explained because of the compressibility of the gas
451phase. In a saturated medium, the water within the system is pushed away from the volume that
452is injected, allowing for the pressure perturbation to move faster, thus reactivating a larger
453region. In an unsaturated medium, the gas phase will be compressed by the injected water. The
454injected water will propagate only to a region close to the injection well, with the pressure
455perturbation following the water front, resulting in the stimulation of a much smaller region.

456Thermal effects on hydroshearing

457The injection of cold water produces changes in temperature distribution. The changes are
458mostly confined around the injection well, and extend only a few tens of meters, with changes up
459to more than 30 °C. Resulting temperature distribution for both the water-saturated and
460unsaturated cases are shown in Figure 6a and c, respectively. Although we have seen how the
461hydrosheared zone can differ between a water-saturated and an unsaturated system, changes in
462temperature are very similar, as already showed for the resulting flow rates (Fig. 4a and Fig. 5a).
463However, these small and confined changes in temperature may have an effect on the resulting
464stress. In essence, the cooling caused by the injection along the permeable (stimulated) zone
465causes cooling shrinkage that in turn tends to cause an additional reduction in effective stress and
466shear strength. Such shear strength reduction will tend to promote shear failure and propagation
467of the stimulation zone. In fact, if we compared a case that considered a hydro-mechanical (HM,
468i.e. considering $\alpha_t = 0$) coupling only with a full THM modeling, we found that the temperature

changes may help the EGS reservoir growth. In fact, when conspiring thermal effects, EGS reservoirs grow about 100 m farther along the NS direction for the case of water-saturated system (Fig6b, THM brown, HM yellow). Some small differences are observed for the case of gas-saturated system, with about 20 m difference between THM and HM modeling, with a slightly larger reservoir when thermal effects are taken into account (Fig6d).

Sensitivity analysis

We have seen how two systems can respond differently to stimulation if we account for the presence of gas. However, the presence of gas within a system is only one of the parameters that should be taken into account when simulating a complex system such as a geothermal reservoir. Some of the parameters can be taken from field studies: for example, the stress field, which plays a huge role in shear reactivation, can be evaluated by *in situ* tests, and by looking at local seismicity. The same can be done for the permeability, although most of the parameters studied in the laboratory analysis can produce results quite different from those observed in the field. Here, we aim to focus only on two main parameters that affect the resulting stimulated volume: (1) the constant K_{HS} for the shear-enhanced permeability (Eq. 6) and (2) the frictional angle ϕ for the Mohr-Coulomb criterion (Eq. 7). All the analyses presented in this section were done at the end of the second stage, i.e., after 51 days of simulation.

In the base-case simulations we set a shear-enhanced permeability change factor to achieve between a 2 and 3 orders magnitude change ($K_{HS} = 500$). However, in the field this factor may be greater (or smaller), leading to a different system response. Figure 7a shows how the EGS reservoir extent varies along the NS direction as a function of this constant for both an unsaturated (red line) and saturated system (blue line). Figure 7b shows the stimulated volume as a function of the shear-enhanced permeability factor. The extent of the region subject to hydroshearing may reach up to 800 m in a water-saturated system, when we consider a factor 10^4

of permeability changes, or may extend for few tens of meters when we do not consider changes in permeability due to hydroshearing ($K_{HS} = 0$). These variations are much smaller for an unsaturated system. Even if we use a factor 10^4 , in a system that is initially gas-dominated, the reservoir may extend up to about 200 m only. From both Figures 7a and b, we found that the hydrosheared region (extent or volume) varies as a logarithmic function of the shear-enhanced permeability factor greater than 10 (i.e. $\log_{10}(K_{HS})$ greater than one):

$$V_{HS}(L_{EGS}) \propto \log_{10}(K_{HS})(K_{HS}) \quad (5)$$

where V_{HS} represents the volume subjected to hydroshearing, which is proportional to the EGS reservoir length (L_{EGS}). Note the logarithmic scale that Figure 7b.

The second parameter for which we perform a sensitivity analysis is the friction angle. For the base-case simulations, we used an angle of 30° , which means a friction coefficient of about 0.6.

This factor can play a big role, depending upon the initial stress condition. Considering a fixed, linear stress distribution, with no heterogeneities and variation in depth, the friction angle simply regulates how much overpressure is needed to satisfy the failure criterion (Eq. 7). Results of the sensitivity analysis for this parameter are shown in Figures 6c and d, for the EGS extent along the NS direction and for the stimulated volume, respectively. Both these variables seem to change linearly with the friction angle, with values ranging between 600 m (volume $2 \cdot 10^8 \text{ m}^3$) and 250 m (volume $5 \cdot 10^7 \text{ m}^3$) for a water-saturated medium with an increase in the friction angle resulting in a smaller stimulated volume and linear extent, and hydrosheared region is almost

512 constant for an unsaturated medium: only a 40 m variation in EGS extent over the considered
513 range of values.

514 **CONCLUSIONS**

515 During stimulation of an Enhanced Geothermal System (EGS) it is always difficult to predict
516 how far the reservoir and fracture network can grow. Moreover, creating a new fracture network
517 requires elevated pumping pressure and flow rates in order to fracture the rock. One mechanism
518 that has been proposed to reduce the cost is so-called *hydroshearing*, which involves reactivating
519 an existing fracture network by a shear process, taking advantage of the fracture surface
520 roughness, which should naturally maintain the enhanced permeability. The pressure needed for
521 hydroshearing has to be below the minimum principal stress, but without exceeding it, thus
522 avoiding then the creation of new tensile fractures. Once the fractures are reactivated, some
523 isolating, thermally degrading material may be injected to plug the fracture network, and this will
524 permit stimulating multiple fracture zone without drill rig or setting multiple packers. Moreover,
525 the injection of chemical diverters will permit injecting at a higher pressure (hence reactivating
526 some other, deeper zones) without changing the flow rate.

527 However, some questions need to be answered: will the presence of gas within the system help or
528 reduce the hydroshearing reactivation? How much can the permeability change after reactivation,
529 and how is that change related to the extent of the EGS reservoir and to the stimulated volume?
530 The aim of this paper was to answer to these questions. Through the use of the TOUGH-FLAC
531 simulator, we carried out a coupled thermo-hydro-mechanical modeling of EGS stimulations. We
532 accounted for a Mohr-Coulomb solid that can fail when a criterion is satisfied. Upon fracture
533 reactivation, we assumed a change in medium permeability, which allows for a better
534 propagation of the pressure perturbation. Taking into account previous simulations performed for

535The Geysers Geothermal Field and starting with data collected at the Newberry Volcano EGS
536Demonstration site, we simulated the stimulation by fixing the overpressure at the top of an
537injection well. Pressure transient evolution was taken as the average of field values measured at
538Newberry Volcano during stimulation. Although our aim was not to reproduce any observed
539variations, we used field data to keep our model as realistic as possible.

540We first presented the results for two limiting cases: (1) a water-saturated medium and (2) a
541medium initially saturated with CO₂ in the gas phase. Results suggest that an EGS reservoir will
542extend much further in a medium initially fully saturated with water than in a gas-phase
543dominated system. We explained this effect as owing to the compressibility of the gas phase. In a
544water-saturated medium, the native water within the system is pressurized by the water injected
545into the well, allowing the pressure perturbation to propagate faster and reactivating fractures
546over a larger region. In an unsaturated medium, the much more compressible gas phase will be
547compressed by the injected water, which will propagate only to a region close to the injection
548well, following the water front, finally stimulating a much smaller region. Thermal effects on
549stress may help to reach shear failure. Although temperature changes are small and confined
550within tens of meter from the injection well, thermal effects on stress are evident at earlier time
551and helped the EGS reservoir to grow. A hydro-mechanical modeling resulted in smaller
552hydrosheared region after the stimulation.

553The presence of gas is not the only parameter affecting the growth of an EGS reservoir. Many
554parameters are involved that may play a significant role, such as the medium initial permeability,
555the natural fracture-network orientation, and the stress distribution. We performed a sensitivity
556analysis on two key parameters that are generally hard to measure in the field: (1) the factor for
557the shear-enhanced permeability changes and (2) the friction angle for the failure criterion.

558Results showed that the extent of the EGS reservoir and the volume subjected to shear

559 reactivation strongly depend upon these two parameters. We found that in our system, the EGS
560 extent (or reactivated region volume) will depend logarithmically upon the constant used to
561 relate permeability change associated with hydroshearing, and linearly upon the frictional angle.
562 These variations are more accentuated in a water-saturated system.
563 The volume subjected to hydroshearing (stimulated volume) ideally should also represent the
564 region where the microseismicity cloud should be. However, natural-system heterogeneities in
565 the stress field and permeability may play a significant role, and the seismicity cloud may not
566 exclusively represent only the region that has been stimulated. For example, a brittle material at
567 shallow depth may be affected by deformation and stress transfer coming from a deeper
568 overpressure, and seismicity may then be induced at a shallower depth than we would expect.
569 Technical issues may be involved as well: for example, a leakage from the cased well may allow
570 the water to move at shallow depths, where it is much easier to cause hydroshearing, or
571 hydrofracturing, since the *in situ* would be stress smaller, generally depending on the depth.

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730

731Tables

732Table 1. Hydrological properties. κ_i initial (stress-free) permeability along i -direction. ϕ porosity.

733 ρ_{rock} rock density. D rock grain specific heat. λ thermal conductivity. c_p pore compressibility

	Newberry-Deschutes	John Day	Intruded John Day	Cased well	Open well
κ_x (m ²)	10^{-17}	$2.6 \cdot 10^{-16}$	$5 \cdot 10^{-18}$	10^{-20}	10^{-16}
κ_y (m ²)	10^{-17}	$2.6 \cdot 10^{-16}$	10^{-17}	10^{-20}	10^{-16}
κ_z (m ²)	10^{-17}	$2.6 \cdot 10^{-16}$	$5 \cdot 10^{-18}$	10^{-8}	10^{-8}
ϕ	10	5	3	95	100
ρ_{rock} (kg/m ³)	2400	2400	2400	-	-
D (J/kg °C)	1000	1000	1000	800	800
λ (W/m °C)	1.80	2.15	2.20	2.20	1.80
c_p (Pa ⁻¹)	$3.2 \cdot 10^{-9}$	$3.2 \cdot 10^{-9}$	$3.2 \cdot 10^{-9}$	-	-

734Figure captions

735

736Figure 1. Mesh and boundary conditions for modeling the stimulation of an EGS reservoir.

737Initial pressure, temperature and stress condition follows pre-stimulation analysis at the

738Newberry Volcano EGS Demonstration, as well as rock properties and distribution.

739

740Figure 2. Model calibration. (a) Pressure well log (blue, dashed line) and simulated pressure (red
741line) after 3 days (09/27/2010) of 0.6 kg/s (10 gpm) injection rate. (b) Temperature well log
742(blue, dashed line) and simulated temperature (red line) after 3 days (09/27/2010) of 0.6 kg/s (10
743gpm) injection rate. (c) Pressure well log (black, dashed line) and simulated pressure (red line)
744after 9 days (10/20/2010) of 1.4 kg/s (22 gpm) injection rate. (d) Temperature well log (blue,
745dashed line) and simulated temperature (red line) after 9 days (10/22/2010) of 1.4 kg/s (22 gpm)
746injection rate.

747

748Figure 3. Example of stimulation. Wellhead pressure (blue) and injection rate (red) observed at
 749Newberry Volcano EGS Demonstration. Gap in timeline is when stimulation pumps were offline.
 750The green line represents an average of the wellhead pressure, which is used as input for our
 751modeling of an EGS system to study the hydroshearing. The shut in period between our first and
 752second stage is indicated in figure. Note that at Newberry during that period the injection
 753continued at a very low rate.

754

755Figure 4. Simulation results for a system fully saturated with water. (a) Applied wellhead
756pressure (red) and resulting flow rate (blue). (b, c) Resulting pressure and hydrosheared zone at
757the end of the first stage (28 days). (d, e) Resulting pore pressure changes and hydrosheared zone
758at the end of the second stage (51 days).

759

760 Figure 5. Simulation results for a system initially saturated with carbon dioxide. (a) Applied

761 wellhead pressure (red) and resulting flow rate (blue). (b, c) Resulting pressure and hydrosheared

762 zone at the end of the first stage (28 days). (d, e) Resulting pore pressure changes and

763 hydrosheared zone at the end of the second stage (51 days).

764

765 Figure 6. (a) Temperature changes after the stimulation and (b) resulting hydrosheared zone for
 766 THM (brown) and HM (yellow) modeling for a water-saturated system. (c) Temperature changes
 767 after the stimulation and (d) resulting hydrosheared zone for THM (brown) and HM (yellow)
 768 modeling for a system initially fully saturated with gas.

769

770 Figure 7. Sensitivity analysis. Blue and red lines refer to saturated and unsaturated systems,
 771 respectively. EGS reservoir extent along NS-direction (a) and hydrosheared volume (b) as a
 772 function of the constant for shear-enhanced permeability (K_{HS} , Eq. 6). EGS reservoir extent along
 773 NS-direction (c) and hydrosheared volume (d) as a function of the friction angle for the Mohr
 774 Coulomb criterion (ϕ , Eq. 7).

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