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Joint opening or hydroshearing? Analyzing a fracture zone stimulation at Fenton Hill

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Abstract

In this study, we analyze a deep hydraulic stimulation of a fracture zone that was conducted as part of the classical Fenton Hill Hot Dry Rock Program in the 1970s. At the time, it was suggested that a pre-existing fracture or multiple fractures within the fracture zone were jacked open by injection-induced increase in pressure. In this study, we analyze the same stimulation experiment, but investigate the possibility of an alternative mechanism of shear reactivation of pre-existing fractures. We conduct modeling that accounts for both jacking (or elastic-fracture opening) and shear-slip dilation and demonstrate that injection-induced shear reactivation (or hydroshearing) could have occurred simultaneously with seismic events of magnitudes lower than what can be felt by humans. In fact, simulations considering shear reactivation seem to better match observed fluid recovery after multiple injection cycles. Shear reactivation and shear dilation results in locked-open fractures, especially near the injection well that provides permeability of higher flow recovery. We then investigate the sensitivity of the proposed model by varying some of the critical parameters such as maximum aperture, dilation angle, as well as fracture density. Interestingly, none of the simulated cases resulted in a large event that could have been felt by humans, but did result in a cumulative seismic magnitude of less than 1 for each given stimulation step. These results suggest that a permanent irreversible permeability increase of several orders of magnitude can be obtained by hydroshearing in a “seismically” safe manner.

Keywords: Hydroshearing, Permeability, Induced seismicity, EGS, HDR

1. Introduction

A critical question to answer for the development of future, innovative, and viable forms of natural deep underground geothermal resources is: Can we avoid human-felt, induced seismicity and still effectively exploit a geothermal reservoir? The next-generation georesources exploitation will require an answer to this question, since induced seismicity currently poses a great challenge to the geoenergy community in terms of monitoring, discriminating, and managing induced seismicity as highlighted in a recent review paper by Grigoli et al. (2017).

The exploitation of deep subsurface georesources frequently requires injection (or withdrawal) of large amount of fluids, affecting the state of stress and pressure at depth and potentially causing fault reactivation. A typical example is geothermal energy production from a hot dry rock (HDR) reservoir: while on the one hand the geothermal energy is considered as the

most promising, clean, and almost inexhaustible form of geoenergy, on the other, the risk posed by associated induced seismicity may still be too high.

Among the other factors influencing the feasibility of an Enhanced Geothermal System (EGS), understanding how the permeability changes with or without induced seismic events (or aseismic slow slip events) still represents a great scientific and economic challenge. The possibility of enhancing the permeability at EGS was demonstrated as far back as the early 1980s by creating the world's first HDR reservoirs at Fenton Hill (Brown et al., 2012). The Fenton Hill experiments demonstrated that fluid circulation can be effectively intensified by stimulating preexisting fractures and fracture zones, opening the path for future commercially viable energy production. The concept of "hydroshearing" involving injection-induced shear activation of preexisting fractures is considered as a promising technique for effectively enhancing reservoir permeability (Cladouhos et al., 2009, 2016). It has been known since the early 1980s that injection-induced hydroshearing of natural joints preferably occurs on fractures optimally oriented for shearing within the local stress field (Pine and Batchelor, 1984). Hydroshearing involves shear reactivation of joints because of a reduction of effective stress and frictional strength and could occur at a fluid pressure much lower than the pressure required to jack open a preexisting fracture or to create a new one (hydrofracturing).

The concept of hydroshearing is being applied worldwide for stimulation of EGS reservoirs (e.g. Tester et al., 2006; Ziagos et al., 2013; Cladouhos et al., 2016) because it is a process which could enhance the permeability of natural fractures in a permanent manner through self-propping even after the stimulation period. However, shear reactivation of fractures can lead to seismicity, which can compromise the success of the project due to public concerns. While on one hand, the seismic activity may represent an indicator of a successful creation of the HDR reservoir, on the other, if the fracture stimulation crosses a large fault or fracture zone, the risk of inducing human-felt seismic events increases. Indeed, induced seismicity has been the cause of halting EGS projects at several locations around the world such as Basel, Switzerland (Häring et al., 2008) or more recently Pohang, South Korea (Kim et al., 2018; Grigoli et al., 2018).

Investigating the relationship among hydroshearing, earthquakes and permeability can potentially help to understand under what conditions fluid-induced seismicity can safely be used as a tool for enhancing reservoir permeability (*i.e.* by avoiding "felt" events). Several studies in recent years have focused on understanding the relationship between fluid flow, geomechanics, and induced seismicity. Laboratory and *in-situ* experiments have been successful in demonstrating the dependency of hydromechanical properties on the injection (e.g. Samuelson and Spiers, 2012; Pluymakers et al., 2014; Guglielmi et al., 2015; Scuderi and Collettini, 2016; Ye and Ghassemi, 2018); while numerical and observational studies have focused on understanding the triggering and propagation of induced seismicity (Goertz-

Allmann et al., 2011; Bachmann et al., 2012; Gischig, 2015; Dempsey and Suckale, 2016; Dempsey et al., 2016; Catalli et al., 2016; Azad et al., 2017; Zbinden et al., 2017).

Other studies have been focused on the dependency of permeability on stress and pressure conditions in rock fractures and fractured rocks. The works by Barton and others in the 1980s were groundbreaking in developing empirical models for relating stress to permeability through systematic laboratory investigations (Barton and Choubey, 1977; Bandis et al., 1983; Barton et al., 1985; Makurat et al., 1990). These works provided models for relating changes in effective normal stress and shear displacements to changes in hydraulic conducting aperture for rock fractures. Rutqvist and Stephansson (2003) argued that determining the relationships between stress and permeability in fractured rock may be best conducted *in-situ* due to issues related to unrepresentative sampling and sampling disturbances when trying to upscale laboratory data. Rutqvist (2015) presents cases of *in-situ* determination of stress-vs-permeability relationships suggesting the scale dependency of this relationship. However, there are still major uncertainties in the quantification of shearing on permeability for various rock types, including crystalline rock and shale. Rinaldi et al. (2014) compared three different models of permeability changes in the context of fault reactivation during CO₂ storage operation. Their results demonstrated a poor correlation between the magnitude of the induced seismic events and the amount of possible CO₂ leakage toward shallow depth. While the observed permeability changes were orders of magnitude, at the large scale of storage reservoir, the same modeling approach may not be appropriate for EGS. Indeed, their model was developed to intentionally trigger “felt” seismic events, which is to say, of a seismic magnitude larger than those commonly monitored during hydroshearing stimulation.

Recently, experimental results by Ye and Ghassemi (2018) provided indications that the hydroshearing involves both processes of shear slip and fracture propagation, and both contribute to enhance the system permeability, although they did not quantify such relationships. A recent review by McClure and Horne, (2014) investigate on the possible stimulation mechanisms at EGS, and while several models have been proposed recently in literature for hydroshearing and fracture opening (Rinaldi et al., 2015a; Norbeck et al., 2018; Salimzadeh et al., 2018; Xiao et al., 2018), the comparison with data is often qualitative with poor sensitivity analysis on the model parameters. In this study, we propose a relation between hydroshearing and permeability increase. In order to have a realistic formulation, we analyze a deep hydraulic stimulation of a fracture zone which was conducted in the Fenton Hill Hot Dry Rock Program. At the time, it was suggested that a pre-existing fracture or multiple fractures within a fracture zone were jacked open by injection-induced pressure increase. In this study, we analyze the same stimulation experiment, but investigate the possibility of an alternative mechanism of shear reactivation of pre-existing

fractures. We conduct modeling that accounts for simultaneous jacking (or elastic fracture opening) and shear-slip dilation and demonstrate that injection-induced shear reactivation (or hydroshearing) could have occurred, aseismically or with magnitudes below the detection threshold at the time of experiment. We then investigate the sensitivity of the proposed model by varying some of the critical parameters such as maximum aperture, dilation angle, as well as fracture density. Finally, we conclude with a discussion including the possibility of enhancing permeability and fluid circulation at an EGS without causing large (felt) seismic events.

2. Fenton Hill observations

The Fenton Hill HDR project is known to be the world's first full-scale EGS project. The overall goal of the concept studied at Fenton Hill was to create a human-made reservoir at 200 °C and circulate water through the use of two deep boreholes (Brown et al., 2012). The project was in operation for more than 20 years, including two different phases, and provided an exceptional amount of data and knowledge. Phase I focused on creating a reservoir and establishing a hydraulic connection between the two wells, constituting the concept of EGS designated at Fenton Hill. One of the main findings of the Phase I HDR reservoir creation was that the hydraulic stimulation in the granitic basement appeared to be related to re-opening pre-existing and sealed fractures with very complex geometries and orientations, rather than creating new fractures. The subsequent Phase II of the Fenton Hill project focused on creating a deeper HDR reservoir at about 4000 m depth, compared to the 3000 m reached during Phase I (Brown et al., 2012).

In order to understand the effect of joint opening and shear reactivation on permeability, we study a series of pressure-stimulation tests that were carried out during stage 2 drilling of the GT-2 well for the Phase I HDR reservoir creation of Fenton Hill. Starting in September 1974, several pressurization tests were performed in Zone 7, a 62-m open-hole interval (1981–2043 m depth) at the bottom of the borehole below a steel-and-cement liner. Pressure data were collected during an initial injection test, denoted as Test 1, when fluid was injected at a rate of 8 l/s for one minute. Fig. 1 illustrates how the pressure reached a leveling off value of 17.2 MPa within the first minute, and it did not show the breakdown pressure typical of hydraulic fracturing, indicating that one or several pre-existing joints had been opened. After one minute of injection, the shut-in curve was nicely recorded for about one hour before venting (Fig. 1 – Blair et al., 1976). The high opening pressure relative to the horizontal minimum stress magnitude suggested that the opened joints could be dipping about 70°. The existence of such joints was further indicated by temperature logs and additional injection tests (Brown et al., 2012). These injection tests with water pumped into the joints at increasing volume helped identifying two distinct joints at 1990–1993 m and 1999–2002 m, respectively. Three further injections were then performed to further inflate the joints with volumes 11,000, 20,000 and 36,000 gal (42, 76 and 98 m³), respectively, at a maximum pressure of 17.2

MPa and a rate of 11 l/s. Unfortunately, the monitoring system failed, hence no pressure data were recorded during these later tests. However, it was observed that for each test much less than half of the injected fluid was recovered during venting (Brown et al., 2012). Fluid recovery largely increased to about 90% in less than one hour after a further test involving the injection of 4500 gal (17 m³) of proppant (water treated with sand) at a rate of 24 l/s. The results of the tests suggested that the joints were trapping fluids by closing after shut-in, but also indicated that the HDR production could be largely enhanced by keeping the joint open at higher fluid pressure (Brown et al., 2012).

Fig. 1. Wellhead pressure recorded during stimulation of Zone 7 of well GT-2 at Fenton Hill after injection of about 105 gal of fluid (0.4 m³). Modified after Blair et al. (1976) and Brown et al. (2012).

The sequence of injection tests in Zone 7 is also part of Problem #2 in the framework of a code comparison study (GTO-CCS – White et al., 2017), which was funded by the U.S. Department of Energy's Geothermal Technology Office (GTO). Problem #2 of the GTO-CCS aimed at understanding the hydro-mechanical response of the joints to fluid injection, shut-in and venting operation for Test 1 and the larger-injection tests (referred as Test 2-4), as well as the injection of proppant (Test 5). Fu et al. (2016) presented results of two modeling teams employing the numerical code CFRAC (Complex Fracturing ReseArch Code – Shiozawa and McClure, 2016) and GEOS (fully coupled hydraulic fracture simulation code – Settgast et al., 2017), respectively. Both teams assumed the presence of a vertical pre-existing natural fracture (or joint) accounting for a relationship between normal stress and fracture aperture, as well as fracture tensile opening and a cubic law to related fracture aperture and permeability. Despite substantial differences in the modeling approach, both models were able to capture most of the field observations, including the shut-in pressure during Test 1, as well as the low recovery after Test 2-4 and high recovery in case of proppant injection (Test 5). Both teams calculated recovery for Test 2-4 as low as a few percent of the injected volume, which the authors interpreted as being caused by the

vertical gradient larger than the fracture opening pressure, resulting in the injected fluid migrating upward. According to the authors, such an effect was largely reduced by the high viscous fluid injected in Test 5, and combined with the relatively small injection and reduced impedance caused a larger recovery ratio. Gao and Ghassemi (2016) report results from another team involved in the GTO-CCS. They proposed a 3D thermo-poromechanical model with an inclined fracture accounting also for the shear displacement into the joint closure law. They also considered a fracture sealed with minerals and used a damage model to consider the propagation of a damage zone along the pre-existing sealed fracture. Their results showed that the fracture aperture as well as the extent of the damage region increased with the amount of fluid injected, and that a greater recovery ratio could be achieved by assuming a larger residual aperture during Test 5 (although an actual proppant injection was not simulated and no significant shear dilation was found in their simulations).

3. Modeling approach

The simulations presented in this work draw inspiration from the GTO-CCS Problem #2 (White et al., 2016). While the goal of Problem #2 is to identify the correct opening mechanics, here we focus on comparing the pure elastic opening vs shear reactivation on permeability, and further investigating this latter case with a sensitivity analysis. Thus, we investigate whether shear reactivation with shear slip dilation could have played a role in addition to elastic joint (or jacking) opening during the series of injections in Zone 7 of the GT-2 well. We updated and improved the TOUGH-FLAC numerical simulator (Rutqvist, 2011) to take into account the newly developed hydro-mechanical coupling routine for permeability changes. TOUGH-FLAC couples the capabilities for simulating multiphase, multicomponent fluid flow of TOUGH2 (Pruess et al., 2012) with the geomechanical calculation performed by the commercial code FLAC^{3D} (Itasca, 2011).

Each simulation of the Fenton Hill experiments at zone 7 of the GT-2 well consists of a 4-test sequence, with each test lasting one day and with injected volume corresponding to the aforementioned Tests 1–4. We fixed the injection rate at 7.9 l/s for all the tests (with total injected volumes of 105, 11,000, 20,000, 36,000 gals – 0.4, 42, 76 and 98 m³ –, respectively, for the four tests), and calibrated our models to reproduce the shut-in curve recorded in the field (Fig. 1). In the modeling, injection takes place at the head of a full-length well, intersecting a joint or jointed zone at a depth of 2000 m. The well, simulated as an equivalent porous medium, is assumed to be closed along its entire length, and it is only open over an interval across the jointed zone, simulating injection directly into the more permeable feature (joint or jointed zone). Venting is simulated in TOUGH2 by using a well in deliverability mode with calibrated productivity index (Pruess et al., 2012). Further model calibration is obtained by estimating parameters for the aperture-stress relationship through the inverse modeling approach provided by iTOUGH2-PEST coupled with TOUGH-FLAC (Rinaldi et al., 2017).

3.1. Model setup

The numerical modeling setup closely follows recent modeling approach aimed at studying induced seismicity in generic scenarios (Rinaldi et al., 2015b; Rutqvist et al., 2015). The model envisioned here aims at understanding the stimulation of a fracture or fractured zone embedded in low permeability host rock. We employed a 3D modeling domain ($3 \text{ km} \times 1 \text{ km} \times 2 \text{ km}$) as representative of the conditions at Fenton Hill (Fig. 2), with geomechanical and hydrogeological properties as listed in Table 1. The fracture zone is simulated with a model that accounts for ubiquitous joints within a 1-m wide jointed zone with elasto-plastic properties (Fig. 2). Such a width was chosen to reduce the number of parameters to be analyzed (*i.e.* the number of fractures corresponds to the fracture density). The fracture zone extends through the entire domain and dips 70° , following indications from tests at Fenton Hill (Brown et al., 2012). Hydraulically the fracture zone is represented as a permeable porous medium, whose permeability depends on the number of joints and their apertures. Mechanically, the joints are simulated as weak planes subjected to a Mohr-Coulomb failure criterion with strain-softening friction. We use a coefficient of friction of $\mu = 0.6$, with a residual value equal to $\mu_R = 0.5$, occurring over a critical plastic shear strain of 10^{-3} .

Fig. 2. Three-dimensional computational domain with full-length injection well. Hydraulic and geomechanical boundary conditions are also shown.

Table 1. Hydromechanical properties. Some of the parameters are calibrated to obtain a match with recorded wellhead pressure during Test 1.

Geomechanical Properties

Vertical stress (σ_v) gradient	26.5 MPa/km (53 MPa at 2000 m) ^a
Maximum horizontal stress (σ_H) gradient	20 MPa/km (40 MPa at 2000 m) ^a

Minimum horizontal stress (σ_h) gradient	16 MPa/km (32 MPa at 2000 m) ^a
Young Modulus (E)	75 GPa ^b
Poisson's ratio (ν)	0.25 ^b
Rock density (ρ_R)	2700 kg/m ^{3a}
Fracture Zone Properties	
Fracture zone dip ($^\circ$)	70 ^d
Young's modulus (E_f)	30 GPa ^c
Poisson's ratio (ν_f)	0.2
Matrix cohesion (C_m)	6 MPa
Matrix Tensile Strength (T_m)	100 GPa ^e
Matrix friction angle (ϕ_m)	75 $^\circ$
Joint Peak Cohesion (C_j)	0
Joint Residual Cohesion (C_j^{res})	0
Joint Tensile strength (T_j)	0
Joint Peak Friction angle (ϕ_j)	31 $^\circ$ ($\mu = 0.6$)
Joint Residual Friction angle (ϕ_j^{res})	26 $^\circ$ ($\mu_r = 0.5$)
Joint dilation (ψ)	Variable
Critical Plastic strain (ε_p^{crit})	10 ⁻³
Hydrogeological Properties	
Pore pressure (p) gradient	9.81 MPa/km (19.6 MPa at 2000 m) ^c
Temperature (T) gradient	40 $^\circ$ C/km
Host Rock permeability (κ)	10 ⁻¹⁹ m ²
Fracture zone permeability (κ_f)	variable (stress-dependent function with calibrated parameters)
Rock Porosity (ϕ)	0.01 (variable for fracture zone if specified)
Pore compressibility (β)	variable (calibrated)
Well Properties	

Permeability (κ_w)	$0.15 \times 10^{-5} \text{ m}^2$
Porosity (ϕ_w)	0.97
Pore compressibility (β_w)	variable (calibrated)
Productivity index (PI)	$6.55 \times 10^{-13} \text{ m}^3$

a. Gao and Ghassemi (2016).

b. Pearson et al. (1983).

c. Fu et al. (2016).

d. Brown et al. (2012).

e. This high value was chosen to prevent fracturing of the matrix.

The critical plastic strain is linked to the “seismological” critical slip distance, which across the fault width of 1 m it would correspond to 1 mm in our case. There is great uncertainty regarding this parameter, and its value has been demonstrated to vary by several orders of magnitude (Ohnaka, 2003) and being dependent on hydraulic conditions (Scuderi and Collettini, 2016). Moreover, both peak and residual friction parameters depend on the rate of slip as well as on water and clay content (Zoback, 2007; Ikari et al., 2009; Samuelson and Spiers, 2012; Kohli and Zoback, 2013). Here we assume average values to avoid the shear reactivation of a large portion of the ubiquitous joint, given that both residual friction and critical plastic strain have a strong impact on the magnitude of induced events, as highlighted by a through model sensitivity (Rutqvist et al., 2015).

Geomechanical and hydraulic boundary conditions are illustrated in Fig. 2. The system is assumed to be at hydrostatic conditions at the beginning of the injection operations (Fu et al., 2016). We assume open fluid-flow boundary conditions (fixed pressure) at top and bottom of the numerical domain. The boundaries at $x = 0 \text{ m}$, $x = 3000 \text{ m}$ and $y = 1000 \text{ m}$ are open to fluid with a fixed pressure gradient, while the boundary at $y = 0 \text{ m}$ is assumed closed. This latter assumption permits modeling merely half of the fault plane due to symmetry. In terms of geomechanical boundary conditions, we assumed rollers at the bottom of the domain and at plane $y = 0 \text{ m}$, while all the other boundaries have a fixed stress gradient. Initially the model is subjected to a normal faulting stress regime (Brown et al., 2012; Fu et al., 2016). The vertical stress σ_v is 53 MPa at injection depth (gradient 26.5 MPa/km), with an initial minimum horizontal stress $\sigma_h = 32 \text{ MPa}$ (gradient 17 MPa/km).

If shearing occurs during the injection, the rupture is permitted to extend within the fracture zone plane. Every time a new patch p is reactivated (one mesh element or more), we define the reactivation as an “event”, which can be seen as either seismic earthquake or aseismic slow slip. The study by Ikari et al. (2013) shows that also slow-slip events could be associated to such slip-weakening behavior. Hence, the modeled “slip event”, given the

conditions at depth (about 80 °C and 40 MPa normal stress) could be representative of very small reduction in frictional coefficient (Scholz, 1998; Urpi et al., 2016) resulting in our “reactivation events” possibly classified aseismic slow-slip. However, as we are not able to evaluate the frequency content of each event we rely on a cumulative energy released as indication for a possible “felt” event (*i.e.* with magnitude larger than what could be perceived by humans).

In order to evaluate the energy released during shear zone reactivation, for each event we calculate an equivalent scalar seismic moment of a seismic event resulting from the same slip area and average slip on it, by using the relation $m_0p = GAd$, where A is the area of the ruptured patch p (including one mesh element or more), G is the shear modulus of the rock, and d is the average slip on the patch. However, such equivalent single-event scalar seismic moment strongly depends on the size of the elements within the reactivating patch, and then on the mesh discretization, which accounts for smaller elements around the injection well. This is particularly true for very small events, with only few mesh elements experiencing slip: as a consequence, events far from injection result, in average, with larger magnitude. In order to minimize such dependency, we calculated, for each test, a cumulative seismic moment by summing all the single contributions $M_0 = \sum p = 1p = Nm_0p$. Finally, an equivalent seismic magnitude is calculated by using an empirical relationship as $\text{cumMw} = 2.3 \log_{10} M_0 - 6.1$ (Kanamori and Anderson, 1975; Kanamori and Brodsky, 2004). With the cumulative magnitude, we minimize the effect of the coarser mesh discretization far from injection well.

3.2. Permeability changes and hydroshearing enhancement

The stress and deformation can have a strong effect on rock permeability (Rutqvist and Stephansson, 2003). The coupled hydromechanical processes are strongly dependent on the site-specific properties, and predicting how much the permeability can change when subjected to mechanical forces is not easy (Rutqvist, 2015). Typical hydromechanical behavior is generally size-dependent, with maximum closure and hydraulic aperture generally increasing for fractures *in-situ* compared to smaller sized fractures in laboratory samples (Rutqvist and Stephansson, 2003).

In fractured rock, joints can generally provide a path for enhanced fluid circulation upon reactivation as a result of change in closing force (change in effective normal stress) and due to shearing processes (shear displacement and change in shear stress). While the first can occur even for small elastic response, the shear-induced permeability in hard crystalline rocks generally requires shear displacement of several millimeters (Lee and Cho, 2002; Rutqvist and Stephansson, 2003). Shear dilation has been proven to effectively increase sample permeability (Olsson and Barton, 2001; Min et al., 2004), although such a dilation is generally limited by the length of the fractures (Rutqvist et al., 2013). The most well-known relation for fracture

normal closure is perhaps the one by Bandis et al. (1983), in which a hyperbolic dependency of the hydraulic aperture on the normal stress was used to fit observations. Recently, Liu et al. (2009) proposed a two-part Hooke's model (TPHM) for describing the relationship between stress and elastic strain, and derived an exponential relationship between stress and aperture that was shown to be accurate to reproduce a large number laboratory data (Liu et al., 2013). The relationship between aperture b_{el} and normal effective stress σ'_n can be simplified as (Rutqvist and Tsang, 2003):

$$(1) b_{el} = b_r + b_{max} \exp(-\alpha \sigma'_n)$$

where b_r is the residual aperture, with b_{max} and α as fitting parameters. These parameters are estimated for each simulation through inverse modeling to reproduce the observation from Fenton Hill Test 1. An example variation is illustrated in Fig. 3a (blue line).

Fig. 3. (a) Exponential stress-aperture relationship with shear induced enhancement and (b) linear increase with threshold for the shear-enhanced aperture.

In this work, we used this exponential relationship combined with what we call “*hydroshearing*” effect, *i.e.* a shear-induced aperture increase. We propose such an effect to shift the elastic curve a certain factor b_{shear} (Fig. 3a, red line) and that could be further enhanced by tensile opening b_{op} such that the final aperture b is:

$$(2) b = b_{el} + b_{shear} + b_{op}$$

The shear-induced aperture and tensile opening are calculated as a function of the plastic strain, which is accumulated during reactivation of the fracture zone if the Mohr-Coulomb criterion is satisfied. The relationship between plastic strain and aperture is:

$$(3) b_{\text{shear}} = \epsilon_{ps} \tan \psi / s_f b_{op} = \epsilon_{pt} w$$

where ϵ_{ps} and ϵ_{pt} are the plastic shear and tensile strain, respectively, and $s_f = n/w$ is the fracture spacing (*i.e.* number of fractures n within the width w of the fracture zone). ψ is the dilation angle that can be used to scale the shear-enhanced permeability (Fig. 3b).

Furthermore, laboratory experiment confirmed the existence of a maximum aperture (Lee and Cho, 2002), hence, the shear-enhanced permeability can also be limited by a maximum value (*e.g.* 100 μm in Fig. 3b). The use of such limits is equivalent to assuming that the permeability of the fracture does not change after reaching a critical plastic strain. For example, considering a dilation $\psi = 1^\circ$, it results in a critical value for the plastic strain of about 6×10^{-3} .

Finally, the permeability of the fracture zone is calculated following the cubic law (Witherspoon et al., 1980):

$$(4) k_f = s_f b^3 / 12$$

assuming a mechanical aperture corresponding to the hydraulic aperture.

We also account for possible porosity change as related to the plastic deformation. Following Hsiung et al. (2005), we assume that the change in porosity due to plastic deformation is:

$$(5) \Delta \phi = \epsilon_{pt} + \epsilon_{ps} \tan \psi$$

The porosity increase can provide additional fluid storage which can affect the propagation of the reactivation front within the fracture zone (Rutqvist et al., 2015).

A similar approach was employed by Rinaldi et al. (2015a), but in that case the permeability always increased by a constant factor distributed in a wide stimulated region and not focused within a specific fracture zone or feature. Similarly, Kelkar et al. (2012) used an approach with fixed permeability increase during their study of shear stimulation at Desert Peak Geothermal Field (Nevada), although with a much smaller permeability increase (only up to a factor 15). More recently, Rinaldi and Nespoli (2017) proposed a model by using a geomechanical-stochastic model of induced seismicity. In such a model, the shear-enhanced permeability is assigned by a slip-dependent equation, with the slip back-calculated using seismological empirical relationship from earthquake magnitude. Given the occurrence of reactivation on distributed so-called “seed” (potential earthquake hypocenter), the result in Rinaldi and Nespoli (2017) shows a scattered permeability distribution, once again not associated to a specific fracture zone or feature.

Hydroshearing is also commonly modeled by considering a network of discrete fractures, in which the individual fractures are explicitly modeled. Such models range from consideration of a sophisticated constitutive law for each fracture (Min et al., 2004; Deb and Jenny, 2017; Salimzadeh et al.,

2018; Xiao et al., 2018) to a more simplified approach accounting for constant increase of fracture permeability upon reactivation (Bruehl, 2007; Karvounis et al., 2014). Recently, the work by Norbeck et al. (2018) aimed at understanding the permeability enhancement mechanisms at the main reservoir stimulation at Fenton Hill. While their model accounted for shear reactivation combined with pre-existing fracture opening and creation of new fractures, they concluded that pure fracturing or pure shear stimulation could not explain field observations, although no quantitative analysis or inverse modeling was performed for each possible mechanism. Hybrid approaches have also been proposed, considering a background fracture distribution averaged on a continuum medium (Tezuka et al., 2005).

Although these approaches can potentially simulate a large number of fractures, the geomechanics are often simplified and rarely consider, for example, a proper formulation of the shearing (seismic/aseismic) process, including frictional evolution and the stress field re-equilibrium in the area affected by hydroshearing reactivation coupled to hydromechanical fluid flow changes. The approach for permeability changes based on combined normal-stress dependency and shear reactivation adopted in this study can be considered a rational approach applied to a continuum model including a fracture zone/fault.

4. Elastic opening vs hydroshearing

In the following section, we present results of some base-case simulations, aimed at reproducing observations during pressure-stimulation experiment at zone 7 of the FentonHill GT-2 well. Two models are considered for a fracture zone with a dominant single fracture: the first model (EL) only accounts for elastic opening within the fracture zone, while the second one (HS) allows for shear, sudden slip along the fracture zone. This second model aims at understanding the effect of hydroshearing on permeability enhancement and fluid recovery during venting. Both models fit the observed pressure evolution very well, with parameters for the stress-dependent permeability function and critical injection well parameters calibrated to reproduce the observed trend (Table 2). Fig. 4a shows the modeled pressure during Test 1 for both the elastic (red line) and the hydroshearing (orange line) model in comparison with the data. For both EL and HS models, the calibrated maximum aperture is well within the range found in laboratory experiments for granite (Lee and Cho, 2002; Luo et al., 2017), while the residual aperture agrees with analysis of *in-situ* pressure tests (Rutqvist et al., 1998). Also the final calibrated permeability is similar to measured value for fractures in granite (Selvadurai, 2015). The calibrated solution is non-unique given the large number of parameters. The fracture zone width (1 m) also affects the calibration if the number of fractures is assumed constant.

Table 2. Model parameters calibrated to reproduce pressure trend recorded during Test 1 at Fenton Hill GT-2 well.

	EL	HS
residual aperture b_r (μm)	18.2	21.1
maximum aperture b_{max} (μm)	1300	569
stress dependency α (MPa^{-1})	0.37	0.45
maximum shear aperture b_{shearmax} (μm)	–	90
dilation angle ψ ($^\circ$)	–	10
number of joints n (–)	1	1
pore compressibility β (MPa^{-1})	0.3×10^{-9}	0.85×10^{-9}
well compressibility β_w (MPa^{-1})	0.4×10^{-9}	0.85×10^{-9}

Fig. 4. Base-case results. (a) Comparison of elastic opening only model (red line) and hydroshearing model with $90 \mu\text{m}$ maximum aperture (yellow line) with data from Fenton Hill, Test 1 (blue line). (b) Pressure evolution for the 4-tests simulation and (c,d) flow at the well for the two cases.

The wellhead pressure for the entire simulation (Test 1–4) is shown in Fig. 4b in red and orange for EL and HS models, respectively. The results of both simulations are in line with the field observation that the pressure at the wellhead never exceeded about 17 MPa (Brown et al., 2012), with the exception of a spike at the beginning of Test 2 for the HS model. Such a spike is due to poroelastic effects (normal effective stress increasing in elements close to the injection well). This effect initially prevents an easy reactivation along the fracture zone, allowing for a shear-enhanced permeability increase after only a few minutes of injection. The two models

differ in the evolution of the wellhead pressure during Test 3–4, although both fit reasonably well the Test 1 pressure evolution and both reach a similar pressure value at end of each test. Indeed, while the EL model shows a peak in pressure at the beginning of each test decreasing as the injection continues, the HS model, in Test 3–4, shows a logarithmic increase peaking to steady state value in few minutes after injection starts (Fig. 4b). Finally, the two models also strongly differ in the amount of flow-back during the venting operation: for the EL model, the flow-back is always lesser than 2% of the injected fluid (Fig. 4c), while for the HS model a larger portion of the injected fluid is flowing back, with the percentage decreasing from about 16% during Test 2 to about 5% in Test 4 (Fig. 4d).

The observed pressure evolution and flow-back during venting is strictly linked to the amount of aperture and permeability changes nearby the injection well (Fig. 5). For the EL model the fracture is jacked open to 200 μm during injection and is snapped shut during venting with residual aperture of about 30 μm , which only slightly increases after each test (Fig. 5a, red line). In terms of permeability, the peak value of about 10^{-12} m^2 is reached during each test, with the residual value during venting always less than 10^{-14} m^2 (Fig. 5b, red line). The aperture and permeability are permanently enhanced for the HS model. After Test 2, the aperture reaches a steady value of about 120 μm , only slightly increasing to about 160 μm during active injection (Fig. 5a, orange line), while the permeability is enhanced by about 2.5 orders of magnitude, from an initial value of 10^{-15} m^2 up to final permeability of about $5 \times 10^{-13} \text{ m}^2$. Fig. 6 shows the evolution of the hydrosheared fracture zone during the four tests in comparison with the cumulative seismic moment magnitude. During Test 1, only a very small portion of the fracture is reactivated (Fig. 6b), with plastic strain of the order of 10^{-5} , capable of only slightly increasing the permeability, but sufficiently to result in a good fit in the pressure curve (Fig. 4a, orange line). The first day of simulation resulted in 3 distinct events (for the used meshgrid) but with a very small, cumulative magnitude of -2.3 (Fig. 6a). The fracture zone is properly hydrosheared during Test 2–4, with its reactivation extent growing to 100, 200, and 300 m from the injection well for Test 2–4, respectively, with a plastic strain up to 1.5×10^{-2} (Fig. 6c–e). The cumulative magnitude for the different patches reactivating through the fracture zone results in a similar value for the three tests: 0.6, 0.5, and 0.5 for the Test 2–4, respectively (Fig. 6a). The number of reactivation events for Test 2–4 is always around 60, although such a number, as well as the cumulative magnitude, could still be somewhat dependent on the mesh discretization, as showed in the supplementary material.

Fig. 5. Modeled fracture aperture (a) and permeability (b) adjacent to the injection well for the elastic opening only model (red line) and hydroshearing model with $90 \mu\text{m}$ maximum aperture (yellow line).

Fig. 6. (a) Comparison between pressure (red line) and cumulative number of reactivation events (blue line), with the cumulative seismic moment magnitude for Test 2-4. (b-e) Evolution of the plastic shear strain on the fault for the four tests. Note the different spatial and color scale for Test 1 (b).

5. Sensitivity of the permeability model

In this section, we investigate the effect of changing certain parameters in the shear-enhanced permeability function. While a change in the maximum allowed b_{shear} as well as including porosity changes does not require recalibration, a change in dilation or in the fracture density (ψ and s_f in Eq. (3)) requires re-calibration of the parameters to achieve a reasonable fit during Test 1. We refer to simulations HS-2, HS-3, and HS-4 for the case of dilation angle equal to 5° , 1° , and 0.1° , respectively, and to simulation HS-5 for the case in which we account for a fracture density of 10 m^{-1} (Table 3).

Table 3. Model parameters calibrated to reproduce pressure trend recorded during Test 1 at Fenton Hill GT-2 well for the sensitivity analysis of the dilation angle (HS-2, HS-3, and HS-4) and of the fracture density (HS-5). The base case model (HS) is reported for comparison.

	HS	HS-2	HS-3	HS-4	HS-5
residual aperture b_r (μm)	21.1	21.0	21.8	22.0	10.4
maximum aperture b_{max} (μm)	569	819.2	862.2	916	738.8
stress dependency α (MPa^{-1})	0.45	0.4	0.38	0.38	0.45
maximum shear aperture $b_{shear,max}$ (μm)	90	90	90	90	90
dilation angle ψ ($^\circ$)	10	5	1	0.1	10
number of joints n (–)	1	1	1	1	10
pore compressibility β (MPa^{-1})	0.85×10^{-9}	0.83×10^{-9}	0.82×10^{-9}	0.81×10^{-9}	0.83×10^{-9}
well compressibility β_w (MPa^{-1})	0.85×10^{-9}	0.83×10^{-9}	0.82×10^{-9}	0.81×10^{-9}	0.83×10^{-9}

5.1. Effect of maximum shear-enhanced permeability

Fig. 7a shows that the maximum shear enhanced permeability has an effect on the pressure: the larger the maximum shear enhanced permeability the lower the pressure at the wellhead. This is due to the residual permeability, which mostly depends on the maximum shear permeability, and only a little on the elastic opening (Fig. 7b). In terms of extent of the reactivated fracture zone, the three cases result in a similar extent value at the end of each test, with the case of $60 \mu\text{m}$ resulting in the largest plastic strain due to larger pressure in the system (Fig. 7c-e).

Fig. 7. Analysis on the maximum shear enhanced permeability for cases with 60, 90, and 120 μm (in red, orange, and violet, respectively). (a) Wellhead pressure evolution (b) Permeability changes (c-e) Extent of reactivated zone and plastic shear strain for Test 2-4.

Table 4 summarizes the results in term of percentage of flow-back during venting, cumulative seismic magnitude and number of reactivated patches. While the cumulative magnitudes are similar for the three cases, the number of reactivated patches per test is higher for the case of 60 μm also showing the lowest flow back percentage. These results suggest that a large number of seismic/aseismic events do not necessarily lead to better enhanced circulation; but more important is the amount of permeability enhanced per single event.

Table 4. Resulting percentage of flow back after venting, cumulative seismic magnitude, and number of reactivations for the analysis of the maximum shear-enhanced aperture.

Case	60 μm			90 μm			120 μm		
Model	HS			HS			HS		
Variables	P_{fb} (%)	M_w	n_{ev}	P_{fb} (%)	M_w	n_v	P_{fb} (%)	M_w	n_v
Test 1	28.5	-2.3	3	28.5	-2.3	3	28.5	-2.3	3
Test 2	8.5	0.6	72	15.7	0.6	61	23.3	0.5	63
Test 3	5.2	0.6	66	9.3	0.5	58	15.1	0.4	59
Test 4	3.4	0.6	65	5.2	0.5	63	8.24	0.5	58

5.2. Effect of amount of fracture shearing

In the base case simulation, we assumed a dilation angle of 10° . Though this parameter has been measured in the lab (e.g., Arzúa et al., 2014), only rough estimates may be possible for *in-situ* fractures (e.g. Olsson and Barton, 2001; Walton et al., 2014). By using the model proposed by Bandis et al. (1983) to the 1-m scale (i.e. similar to the width of the fracture zone in the model), the peak dilation could be expected to be reached after about 1 cm slip (Rutqvist and Stephansson, 2003). Assuming a dilation angle as low as 0.1° , this can still result in a permeability increase by a factor ~ 10 only based on shear slip and without considering effective normal stress changes. Furthermore, some other effects (e.g. gouge formation during shear) would result in a hydraulic aperture not proportional to mechanical aperture changes due to shear dilation. Finally, changes in hydraulic aperture could be smaller than the mechanical apertures which are calculated by the proposed model. All these considerations could justify a lower dilation angle compared to the base case, whose value was chosen based on previous data for granite and numerical experience (Arzúa et al., 2014; Rutqvist et al., 2015). A lower dilation angle can indeed have a large impact on the resulting pressure and flow, and we have performed a sensitivity analysis by choosing a dilation angle ψ (Eq. (3)) with values 10, 5, 1, and 0.1° , which are based on the tests results for centimeter to meter scale samples (Barton, 1982; Olsson and Barton, 2001). Assuming a different dilation angle, results are in a good match in Test 1 only if the elastic opening constants (b_r , b_{max} , and α) are re-calibrated (Table 3 – model HS-2, HS-3, and HS-4 for dilation 5, 1, and 0.1° , respectively). Fig. 8a shows that the pressure follows a similar evolution for the cases of 10, 5, and 1° dilation angle (red, orange, and violet line, respectively), despite reaching a different maximum value at wellhead at the end of each test. This evolution is explained by the permeability variation

around the injection well: it results in a larger permeability increase for the case of 1° dilation angle (Fig. 8b). Such a result is indeed counterintuitive, given the linear dependence of the b_{shear} on the tangent of dilation angle (*i.e.* the larger the dilation, the larger b_{shear} – Eq. (3)). However, an analysis of the simulated plastic strain and of the extent of the fracture zone supports the observed result (Fig. 8c, inset). While the fracture zone extent does not differ starkly for the three cases, some differences can be seen in the plastic shear strain (Fig. 8c-e). In the case of low dilation (1° and 5°), the permeability increase by shearing is small given our formulation (Fig. 3), especially at an early stage. This favors a fast increase in pressure, resulting in a tensile opening in the vicinity of the injection well. The opening causes an increase of plastic tensile strain compared to the 10° case (Fig. 8c – red, orange, violet for 10, 5, and 1° , respectively). Hence, the smaller the dilation, the larger the b_{op} in Eq. (2), the larger the permeability.

Fig. 8. Analysis of amount of fracture shearing for cases with 10, 5, 1, and 0.1° of dilation angle (in red, orange, violet, and green, respectively). (a) Wellhead pressure evolution (b) Permeability changes (c–e) Extent of reactivated zone and plastic shear strain for Test 2–4.

The case of very low dilation (0.1°) shows slightly different behavior compared to the other cases. Fig. 8a (green line) shows larger pressure in Test 2 decreasing in the subsequent tests. This behavior is explained by the variation of the residual permeability, which increases after each test (*i.e.* the maximum shear enhanced permeability is only reached after several tests). For this latter case, the extent of reactivated patches is slightly smaller compared to the previous cases but always with a larger plastic strain observed within the fracture zone (Fig. 8c–e, green line).

Table 5 lists the results in terms of percentage of flow back for each test and case. Test 1 flow back is highest for the largest dilation angle, as expected from Eq. (3) for small ruptures as the ones occurring after only one minute injection. For Test 2, the largest flow-back is observed in the cases of 1° dilation (22.9%), for Test 3 cases of 1° and 0.1° dilation results in the largest flow-back (14.5%), while for Test 4 the percentage of flow-back is higher for the case of 0.1° dilation (11.7% compared to 5.2% of the base case). The results in flow-back percentage reflects changes in permeability, and in the long term the case with the lowest dilation shows a larger flow-back because of larger permeability changes and larger plastic shear strain. All the four cases result in similar cumulative seismic magnitude and number of reactivated patches, with the case of 0.1° dilation resulting in a slightly larger cumulative seismic magnitude, due to larger slip (*i.e.* larger plastic strain) observed at the reactivated patches (Fig. 8c-e).

Table 5. Resulting percentage of flow-back after venting, cumulative magnitude, and number of reactivations for the analysis of the dilation angle.

Case	10			5			1			0.1		
Model	HS			HS-2			HS-3			HS-4		
Variable S	p _{fb} (%)	M _w	n _e v	p _{fb} (%)	M _w	n _e v	p _{fb} (%)	M _w	n _{ev}	p _{fb} (%)	M _w	n _e v
Test 1	28.5	-2.3	3	24.7	-2.2	3	22.9	-2.3	3	22.4	-2.4	1
Test 2	15.7	0.6	61	16.8	0.6	66	22.0	0.7	70	14.6	0.7	72
Test 3	9.3	0.5	58	10.2	0.5	59	14.5	0.6	65	14.5	0.7	66
Test 4	5.2	0.5	63	5.8	0.5	77	8.5	0.6	70	11.7	0.7	69

5.3. Effect of porosity changes and joint density

Fig. 9, Fig. 10 show the resulting pressure, permeability and extent if porosity changes are included in the coupled hydromechanical formulation and if the number of joints is increased. Notwithstanding the pressure oscillations, accounting for porosity changes in the fluid mass balance also result in a larger storage volume for the fluid during fracture opening. Indeed, while the pressure at the wellhead is similar to the base case (Fig. 9a), and while the permeability variation is almost identical to the base case (Fig. 9b), the extent of the reactivated fracture zone is much smaller for the case with porosity changes. This results in smaller flow-back percentage as well as lesser numbers of events and lower cumulative seismic magnitude in all tests (Table 6).

Fig. 9. Analysis of porosity changes (red) compared to base case (orange). (a) Wellhead pressure evolution (b) Permeability changes (c-e) Extent of reactivated zone and plastic shear strain for Test 2-4.

Fig. 10. Analysis of fracture density. Orange lines are for the base case, while red represent a case with fracture density 10 m⁻¹ (a) Wellhead pressure evolution (b) Permeability changes (c-e) Extent of reactivated zone and plastic shear strain for Test 2-4.

Table 6. Resulting percentage of flow-back after venting, cumulative magnitude, and number of reactivations for the analysis of the porosity changes and fracture density.

Case	without porosity changes			with porosity changes			Fracture density 10 m^{-1}		
Model	HS			HS			HS-5		
Variables	p_{fb}	M_w	n_{ev}	p_{fb}	M_w	n_{ev}	p_{fb}	M_w	n_{ev}
Test 1	28.5	-2.3	3	28.5	-2.3	3	24.0	-2.5	3
Test 2	15.7	0.6	61	13.3	0.4	51	35.9	0.6	67
Test 3	9.3	0.5	58	8.4	0.4	37	30.8	0.5	61
Test 4	5.2	0.5	63	4.9	0.5	55	18.4	0.5	70

On the other hand, assuming a larger number of joints within the fracture zone results in a lower pressure at wellhead (Fig. 10a), reflecting the larger permeability with respect to the base case (Fig. 10b). The extent of the reactivated fracture zone is similar for the two cases, although assuming a higher joint density results in a slightly elongated fracture zone toward shallow depths, but with a smaller amount of plastic strain (Fig. 10c-e). This larger extent with small plastic shear strain, results in a slightly larger number of reactivated patches in Test 2-4. This larger number of reactivated patches further enlarges the stimulated region but interestingly with the same seismic cumulative magnitude as in the base case (Table 6). In terms of percentage of flow back during venting, a larger number of joints results in much higher amounts, with about 36%, 31%, and 18.5% of the injected fluid flowing back.

6. Discussion and conclusion

In this paper, we present a model for hydroshearing permeability enhancement during stimulation of an Enhanced Geothermal System. We set up our model to represent conditions that were observed at one of the injection experiments at the Fenton Hill project, with similar injection strategy. The proposed model of permeability enhancement accounts for stress-dependency and for shear-enhanced aperture as function of the plastic strain due to reactivation of fracture zone patches, simulating hydroshearing. Such a process has been shown to provide the necessary permeability increase for an enhanced fluid circulation. While a model accounting for only a stress-dependent permeability (elastic opening) is able to reproduce observations from the Fenton Hill project (*i.e.* the pressure curve in Test 1 and a low flow back during venting), the hydroshearing model, calibrated to reproduce a similar pressure transient at the wellhead, results in a much higher flow-back volume.

The very low flow-back ratio of a few percentage points calculated for the case of elastic opening only is consistent with the results of previous models in which hydro-shearing did not occur for an assumed vertical fracture (e.g. Fu et al., 2016). The observed flow-back ratio at Fenton Hill is reported as “much less than half” in Brown et al. (2012). Our interpretation is that “much less than half” would generally not be as low as a few percent, but could be on the order of ten percent or multiples thereof, though always less than 50%. Based on such interpretation, our results of flow-back ratio of about 10–30% when considering shear dilation seem to better match the observed flow-back rate. Moreover, if the pre-existing fractures were inclined 70° in the field, our calculation suggests that shear activation would very likely be based on the best estimated stress field at Fenton Hill. However, it is important to mention the current results are not unique, as a full record of the pressure is not available for all tests performed in the field.

We further investigated the sensitivity of the proposed hydroshearing model with respect to some critical parameters such as the maximum aperture allowed upon shear reactivation, the dilation angle, as well as evaluated the effect of including porosity changes and a more densely jointed fracture zone. Results show that a larger enhancement is not always linked to the number of reactivated fracture zone patches (*i.e.* seismic/aseismic events), but mostly depends on the site-dependent characteristic. Indeed, the highest flow-back is achieved for a system highly jointed with a large number of reactivated patches, although with a small cumulative magnitude as result of limited deformation and pressure. The evolution of fracture zone porosity as related to aperture changes and how this translates into actual fluid storage in the fluid mass balance has an important impact on the extent of the stimulated region for a given injection volume. Generally, fractures can be complex and branching with additional micro-cracks and damage close to the fracture surfaces that could provide for additional storage and thereby impact the stimulation.

The presented work highlights once again the complex interaction which takes place during stimulation of a reservoir. Very often in the field a balance between induced seismicity and permeability enhancement is in place, and achieving a sustainable energy production while reducing the risk of induced seismicity is not to be treated only from a seismological perspective, but a multi-disciplinary approach is essential. The simulation results highlight the fact that permeability of a fracture zone can be enhanced with relatively small, sequential reactivations. Indeed, none of the simulated cases resulted in a large (*i.e.* “felt”) event, but the cumulative magnitude was always less than 1 for each stimulation test. Assuming an appropriated site, the simulation results suggest that fluid circulation could be enhanced without inducing large seismic events. Furthermore, these same results highlight the importance of monitoring not only for seismic activity, in particular for storage projects, given the possible aseismic (*i.e.* slow slip creeping or with

seismic magnitude below measurable threshold) creation of permeable pathway compromising the sealing capacity of a given site.

There is still a dearth of knowledge or hard data showing the effect of shear activation on permeability at a larger scale. In this study, we back-calculated possible shear activation of a large pre-existing fracture or fracture zone. This analysis was based on flow and pressure analysis, whereas a more conclusive analysis would be possible only with simultaneous measurements of flow and deformations. Such measurements have recently been proposed as ISRM suggested method and conducted in shale and limestone (Guglielmi et al., 2015), as well as in crystalline rocks, relevant for EGS, but with results yet to be evaluated (Amann et al., 2018).

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