A Novel Thermal-Hydraulic-Mechanical Model for the Enhanced Geothermal System Heat Extraction

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Abstract

The present work reports on the development of a three-dimensional transient model, which describes the multi-physical coupling of thermal (T), hydraulic (H), and mechanical (M) processes during heat extraction of enhanced geothermal systems (EGS). The model encompasses: 1) local thermal non-equilibrium to formulate the convective heat exchange between rock matrix and heat transfer fluid in the reservoir, 2) sub-modules describing temperature- and pressure- dependent thermophysical properties of water, and 3) a thermo-poroelastic model, which is used to calculate the effective stress in the rock matrix and to determine the time-changing local porosity and permeability in the reservoir. Analyses for an idealized EGS indicate that an increased effective stress in the rock matrix yields significant mechanical effects upon the EGS heat extraction performance, namely: for a given injection pressure the mass flow rate of fluid is enhanced, leading to improved heat extraction, while the life expectancy of the EGS is shortened. It is found from additional simulations that: 1) a decrease in injection temperature and an increase in injection pressure can lead to an increase at the magnitude of the negative effective stress, which, in turn, can enlarge the porosity and permeability in the heat reservoir, and 2) a smaller value of h_a reduces the heat exchange between the rock and the fluid as it reduces the magnitude of the effective stress.

Keywords: THM coupling; local thermal non-equilibrium; thermal-pore-elastic model; enhanced geothermal system.

1. Introduction

Simulation of the heat extraction process and prediction of the amount of heat that can be extracted from an enhanced geothermal system (EGS) require relatively sophisticated tools; therefore, these tasks still remain a major challenge in geothermal engineering and industry [1-2]. To address this challenge, the development of reliable numerical models dealing with the inter-coupled Thermal– Hydraulic– Mechanical (THM) process in EGS subsurface reservoir should be a priority. Koh et al. [3] state that circulating cold fluid into the reservoir can lead to large amounts of stress energy release inside the rock matrix. The broader scenario is to know how the EGS performance is related to the production temperature, mass flow rate of circulation fluid, life expectancy and heat extraction ratio taking into consideration coupling of the THM processes. Undoubtedly, numerical modeling may prove to be the only expedite way to obtain reliable answers to these questions.

During the past three to four decades, considerable effort has been placed on the development of THM modeling. Several relevant numerical studies related to EGS heat extraction are available from the open literature. Rutqvist [4], Rutqvist et al. [5], and Jeanne et al. [6] reviewed the models developed for hydromechanical coupling in an aquifer and they summarized a number of well-known empirical approaches for the estimation of normal stress across fractured medium. Ghassemi and Zhou [7], Ghassemi et al. [8], and Rawal and Ghassemi [9] numerically investigated the poroelastic and thermoelastic responses of a reservoir or fractures in a reservoir upon the injection of cold water. McDermott et al. [10], and McDermott and Kolditz [11] studied the influence of THM coupling on heat extraction from a reservoir in crystalline rocks with an experimentally validated geo-mechanical model. The results indicated that changes of aperture and closure of a fracture were primarily caused by the variation of normal stress acting upon the fracture; moreover, the normal stress, through the thermal stress component might induce major changes of reservoir permeability. It may be expected that physical properties of the injected fluid, such as density, viscosity and heat capacity, can play a significant role in the fluid-rock interactions. Zhao et al. [12] established a THM coupled model for the hot dry rock (HDR) geothermal energy extraction process based on an idealized EGS geothermal field located in Tengchong, China. Based on the simulation results, they found that fluid seepage resistance

gradually decreased with the running of EGS, indicating strong mechanical effects on the EGS heat extraction. Hu et al. [13] classified the methods developed to handle THM coupling as: loosely coupled, iteratively coupled, explicitly coupled, and fully coupled method. The fully coupled method, which is the aim of the present work, solves the thermal, hydraulic and mechanical equations simultaneously on the same discretized grid system, and Hu et al. [13] reiterated that was the most internally consistent and rigorous method. However, it is very computationally intensive due mainly to the primary variable solved for the mechanical process, which is the rock displacement or velocity vector containing multiple components. As an alternative, they proposed a new THM fully coupled model, in which the mean total stress, a scalar, is solved in the mechanical model, greatly reducing the computational effort. Lei et al. [14] developed a mechanical module based on the extended Biot consolidation model and incorporated into the TOUGH2 model, resulting in an integrated THM model, TOUGH2Biot. They used the TOUGH2Biot to simulate geothermal exploitation for Geysers geothermal field and found that the change in effective stress due to temperature decrease was greater than that caused by pressure decrease in the vicinity of the production well.

Although the body of literature dealing with EGS performance using the THM coupling approach is extensive, in general, there is lack of a thorough and comprehensive study, for instance, the effects of the injection parameters and local thermal non-equilibrium between rock and fluid on the THM coupling process have been somewhat neglected in previous studies. The present work addresses this particular lacuna in the literature, and reports a transient, three-dimensional model, which takes into consideration the full inter-couplings of the THM processes during EGS heat extraction. For the modeling of the subsurface heat exchange process, it is assumed local thermal non-equilibrium [16-18] between the rock matrix and fluid flowing in the reservoir, and temperature- and pressure- dependent fluid properties are implemented to describe the bi-directional TH coupling. The thermo-poroelastic model by Hu et al. [13] is employed to formulate both the TM and HM coupling. Case studies will be performed to analyze the developed model and to study the THM inter-coupling mechanisms during EGS heat extraction. In addition, a numerical study will be conducted to examine how to control the TH parameters with the aim of obtaining a favorable mechanical field for the EGS heat extraction.

2. THM coupling model for EGS heat extraction

2.1 Model equations

The focus of the present work is on the heat extraction from the EGS subsurface reservoir and it is considered an idealized EGS consisting of an injection well, a production well or multiple production wells, heat reservoir, and rocks enclosing the reservoir, as described in our previous publications [16-20]. With major assumptions like: 1) the heat reservoir is treated as equivalent to a porous medium with uniform porosity ε and permeability K ; 2) the heat reservoir is fluid saturated without trapped gas in the rock fractures; 3) rocks enclosing the reservoir are impermeable, i.e. the fluid loss is not considered; 4) the fluid flow in heat reservoir is the single-phase laminar flow and the Reynolds number is sufficiently low to suffice the applicability of Darcy law; 5) local thermal non-equilibrium is considered between solid rock matrix and fluid flowing in the fractures; 6) the walls of production/injection well borehole are thermally adiabatic, the model equations describing heat transport and fluid flow are formulated below [15-20].

Fluid continuity equation:

$$\frac{\partial(\varepsilon\rho_f)}{\partial t} + \nabla \cdot (\rho_f \mathbf{u}) = 0 \quad (1)$$

Fluid momentum equation:

$$\frac{\partial(\rho_f \frac{\mathbf{u}}{\varepsilon})}{\partial t} + \nabla \cdot \left(\rho_f \frac{\mathbf{u}}{\varepsilon} \cdot \frac{\mathbf{u}}{\varepsilon} \right) = -\nabla p + \nabla \cdot \mu \nabla \frac{\mathbf{u}}{\varepsilon} - \frac{\mu}{K} \mathbf{u} + \rho_f \mathbf{g} \quad (2)$$

Energy equation for heat transport in solid rock or rock matrix in the heat reservoir:

$$\frac{\partial[(1-\varepsilon)\rho_s c_{ps} T_s]}{\partial t} = \nabla \cdot (\lambda_s^{\text{eff}} \nabla T_s) - ha(T_s - T_f) \quad (3)$$

Energy equation for heat transport in the fluid:

$$\frac{\partial[\varepsilon\rho_f c_{pf} T_f]}{\partial t} + \mathbf{u} \cdot \nabla (\rho_f c_{pf} T_f) = \nabla \cdot (\lambda_f^{\text{eff}} \nabla T_f) + ha(T_s - T_f) \quad (4)$$

where $\mathbf{u}$, p , T_f and T_s are the primary variables to be solved, denoting the superficial fluid velocity vector, fluid pressure, fluid temperature, and rock temperature, respectively; ρ_f , ρ_s are the density of the fluid and solid rock, respectively; c_{pf} , c_{ps} are the specific heat capacity of the fluid and solid rock, respectively; λ_f , λ_s are the heat conductivity of the fluid and solid rock, respectively. The

effective heat conductivity for the rock matrix, λ_s^{eff} , and for the fluid, λ_f^{eff} , are determined on the basis of their volume fractions raised to the power of 1.5 by the Bruggeman correction, i.e. $\lambda_s^{\text{eff}} = \lambda_s(1-\varepsilon)^{1.5}$ and $\lambda_f^{\text{eff}} = \lambda_f\varepsilon^{1.5}$, respectively; h denotes the convective heat transfer coefficient between rock matrix and fluid in the reservoir, and a the specific surface area of the fractures. The last terms of Eq. 3 and Eq. 4, $\pm ha (T_s - T_f)$ describe the heat exchange between rock matrix and fluid in the reservoir; the negative sign of this term in Eq. 3 means the heat is extracted from the rock and the positive sign of this term in Eq. 4 means the heat is absorbed by the working fluid. The fluid properties in the above equations including ρ_f , μ , c_{pf} and λ_f are considered to be dependent on the fluid pressure and temperature. In the present work, we adopt the International Association for the Properties of Water and Steam (IAPWS) models [21-23] to determine the temperature- and pressure- dependent thermophysical properties of water. The so-called single-domain treatment [16] was employed for the model geometry, namely: $\varepsilon = 0$ and $K = 0$ in the solid rock region, $\varepsilon = 1$ and $K = \infty$ in the injection and production wells, and ε and K have finite values in the porous reservoir. This single-domain treatment allows the unified mathematical description (Eqs. (1) and (2)) to fluid flow in different regions and, in this way, it simplifies the computational treatment of the interfaces between these regions.

By assuming the reservoir rock as linearly elastic with its deformation obeying the generalized Hooke's law, Hu et al. [13] derived a mean total stress equation to describe the mechanical stress field for thermo-poroelastic systems, as follows:

$$\frac{3(1-\nu)}{(1+\nu)} \nabla^2 \sigma_m = \frac{2\alpha(1-2\nu)}{(1+\nu)} \nabla^2 p + \frac{6\beta B(1-2\nu)}{(1+\nu)} \nabla^2 T - \nabla \cdot \mathbf{F} \quad (5)$$

where, σ_m denotes the mean total stress, ν is the Poisson's ratio of rock, α the Biot's coefficient, β the linear thermal expansion coefficient, and B the bulk module of the rock. The three terms on the right hand side of Eq. (5) describe the effects of the poroelastic stress, the thermoelastic stress and the external body force, respectively.

2.2 THM Coupling

As already stated, the THM processes during EGS heat extraction are related to each other, and while fluid flow results in convective heat transport, fluid pressure and temperature induce stresses in the rock or rock matrix. The mechanical process in the rock or rock matrix affects the

TH processes as porosity and permeability in the reservoir are related to the stress field in the rock or rock matrix. The porosity and permeability are two key parameters managing fluid flow and affecting EGS heat extraction. They are not constant, but vary in response to the stress state of rock or rock matrix during EGS heat extraction. Previous studies [13-14] used empirical relations to determine the porosity/permeability as a function of the effective stress. The effective stress (σ'), in terms of the mean total stress (σ_m) calculated from Eq. (5), is determined by the following relation [5, 12]:

$$\sigma' = \sigma_m - \alpha p \quad (6)$$

For porous rocks, the isotropic hydraulic properties are sequentially corrected using empirical porosity-effective stress and permeability-porosity relationships. The porosity-effective stress and permeability-porosity relations are formulated on the basis of the laboratory measurements conducted by Davis and Davis [24], namely

$$\varepsilon = \varepsilon_r + (\varepsilon_0 - \varepsilon_r)e^{-\xi\sigma'} \quad (7)$$

$$K = K_0 e^{\zeta(\varepsilon/\varepsilon_0 - 1)} \quad (8)$$

where the subscripts 0 and r denote the parameter values under a zero effective stress and a reference high effective stress, respectively; the exponentials ξ and ζ are constants. The different constants in Eqs. (6)-(8) are [5, 24]: $\alpha=1.0$, $\xi=5.0 \times 10^8 \text{ Pa}^{-1}$, $\zeta=22.2$. The results in Rudqvist et al. [5] imply that when the porosity and permeability are within 0–0.2 and 0.001–100 mD, respectively, Eqs. (7) and (8) are applicable.

2.3 Numerical methodology

The governing equations, Eqs. (1)- (5), along with the required boundary conditions and initial conditions are solved in the commercial CFD (Computational Fluid Dynamics) flow solver, Fluent®, which is based on the finite volume approximation. The governing equations can be re-written as a generic equation, as follows:

$$\frac{\partial(\varepsilon\Phi)}{\partial t} + \nabla \cdot (\mathbf{u}\Phi) = \nabla \cdot (\Gamma_\phi \nabla \Phi) + S_\phi \quad (9)$$

where Φ denotes the generic variable; Γ_ϕ , the generic diffusivity; S_ϕ , the generic source. These variables for Eqs. (1) - (5) are summarized in Table 1.

By customizing the flexible User Defined Functions (UDF) available in Fluent®, non-standard scalar transport equations, i.e. Eqs. (3) - (5), and various source terms, geo-physical properties, and non-standard advection-convective terms in the governing equations are implemented. The well-known SIMPLE (Semi-Implicit Method for Pressure-Linked Equation) algorithm is used to address the pressure-velocity coupling. The first order upwind differencing scheme is generally used for the discretization of the spatial-derivative terms and a fully implicit scheme for discretization of the transient terms. To accelerate convergence, the AMG (algebraic multi-grid) iterative method is applied to solve the linearized algebraic equations.

3. Case study

3.1 EGS subsurface geometry and other model parameters

The geometry of an idealized quintuplet EGS considered in the present work is schematically shown in Fig. 1. This quintuplet well layout pattern has been commonly used in EGS numerical modeling, by Shaik [15] and Pruess [25] to name a few. The artificial heat reservoir is a 500 m $\times$ 500 m $\times$ 500 m cubic volume. The injection and production well boreholes penetrate the reservoir and all have 0.2 m $\times$ 0.2 m squared cross-section on the xy -planes. The center of the reservoir is located at 4000 m underground. The simulated domain is a 2000 m $\times$ 6000 m $\times$ 2000 m hexahedral volume, which is large enough to avoid any boundary effects during the time-duration of interest, i.e. the thermal disturbance due to heat extraction in the reservoir will not propagate to the simulated domain boundaries at the end of EGS operation.

Due to geometrical symmetry, only a quarter of the geometry is simulated, as shown in Fig.1 (b). The boundary surfaces including the xz -plane with the minimum y value and the yz -plane with the maximum x value are set as symmetric boundary; all the other outer surfaces of the computation domain are specified as zero-flux boundary for all the primary variables except the temperature, which has fixed values at these boundary surfaces. At the walls of injection/production well borehole, the non-slip flow condition is prescribed. The interfaces between sub-regions inside the simulated domain are taken as interior surfaces and can be automatically handled by the numerical code. Initial temperature of the rock is assumed to increase linearly against the depth direction ($-z$) with a gradient of 4 K per 100 m and a ground temperature of 300 K. The initial temperature of the working fluid is assumed to be locally the

same as that of the rock. During heat extraction, cold fluid with a temperature of 343 K is injected into the heat reservoir under a prescribed 10 MPa pressure difference between the injection well inlet and the production well outlet. A constant reference value of 40 MPa is assigned to the pressure at the center of heat reservoir. Table 2 summarizes the values for all the major parameters considered in the case study. Physical parameters, porosity, permeability and volumetric heat transfer coefficient are taken from Ghassemi et al. [7-8], Rudqvist et al. [5], Hu et al. [13] and Jiang et al. [16], respectively, and are listed in Table 2.

Numerical tests about the adequacy of the mesh system indicated changes of less than 2% from a mesh of 100,000 elements to one with 150,000. Further increase to 200,000 elements produced negligible differences at the resultant pressure, temperature and mean total stress distributions in the subsurface reservoir. Therefore, the mesh system of 200,000 elements has been adopted.

3.2 Evolution of temperature, pressure and stress

Time development of rock temperature in the reservoir is presented in Fig. 2. As cold fluid is injected into the reservoir, heat stored in the rock matrix is gradually extracted by the fluid and a low temperature region is formed around the injection well. This low rock temperature region gradually expands toward the production well with the time progression of the EGS heat extraction.

For homogeneous reservoir with low permeability (lower than $\sim 10^{-12} \text{ m}^2$), the Darcy resistance in porous heat reservoir is much larger the flow resistance and static pressure difference in the open channel well borehole; the fluid flow in the reservoir will mostly take place in the horizontal plane, and the Z-direction flow can be safely neglected. [20] Time development of pore pressure in the reservoir is reported in Fig. 3. At the bottom of the injection well, the fluid pressure takes the highest value and at the position of the production well exiting the reservoir, the fluid pressure takes the lowest value. The pore pressure remains high only in a very limited region close to the injection well borehole, indicating that most of the flow resistance occurs in this region.

Fig. 4 presents the transient evolution of the mean total stress in the rock matrix of the heat reservoir. There exists a region of positive mean total stress in the vicinity of the injection well;

however, further away from the injection well it is located a region of negative mean total stress, which increases with the progress of the EGS heat extraction.

3.3 Analysis of stresses

The mean total stress in the reservoir represents a combined effect of poroelastic pressure and thermoelastic stress. In order to differentiate the influence of hydraulic and thermal field on the stress field, the stresses caused by pore pressure and temperature change are compared in Fig. 5. It can be seen that the stress caused by pore pressure is a compressive stress and is constrained to a very small region around the injection well, while the stress caused by temperature change is a tensile stress and it influences a region larger than that acted upon by the compressive stress; however, the magnitude of the stress caused by pore pressure is higher than that of the thermal stress.

For further understanding of the formation mechanism of thermoelastic stress during the EGS heat extraction process, the calculated fluid and rock temperature profiles, and thermoelastic stress profile along line AB, position of which is shown in Fig. 5, after 5 years of EGS operation are reported in Fig. 6. The rock and fluid temperature profiles evidently show 3 distinct heat extraction regions. Within the first region, about 60 m distance from point A, heat stored in the rock has been fully extracted, and the fluid temperature remains unchanged and shows no difference in relation to the rock temperature. Heat extraction occurs primarily in the second region, about 60 - 230 m away from point A, where the rock and fluid generally have a difference in temperature of 1-2 K. In the third region that occurs more than 230 m away from point A, the fluid is fully heated up by the rock in the second region and its temperature is approximately equal to the local rock temperature. The thermal stress in the rock, as expected, it reflects the thermal-state of the rock; because the thermal stress results from the temperature difference, initially, the hot rock presents no thermal stress. Once the rock temperature is lowered by the cold fluid injected, it contracts and thermal stresses do occur. In the first region, about 60 m away from point A, for 5 years of EGS operation, the rock is completely cooled down by the fluid and it displays the largest thermal stress, -1.6 MPa, where the negative sign indicates a tensile stress. In the third region occurring at a distance from point A higher than 230 m, the rock is still in its initial thermal-state and the thermal stress is practically zero. In the second region, which comprised

between 60 m and 230 m away from point A, the rock temperature is lowered by the fluid, and the thermal stress falls in the range of -1.6 MPa to 0 MPa.

3.4 EGS heat extraction coupled with stresses in rock

EGS heat extraction process is tightly coupled with the mechanical process in the rock as the porosity and permeability in the reservoir are related to the effective stress in the rock. Fig. 7 displays the calculated effective stress, porosity and permeability in the reservoir after 5 years of EGS operation. The effective stress is negative, which indicates that tensile effects on the reservoir pore-structure, and in the near-region to the injection well, the magnitude of the effective stress takes relatively larger values. The porosity and permeability in the whole reservoir are both enlarged due to the effects of tensile stress, and in the near-region of the injection well this effect on the porosity and permeability is further increased. The maximum increment of the porosity is only about 3% (from 0.0100 to 0.0103) whereas the permeability presents markedly changes. The maximum permeability is about two times of its initial value in the vicinity-region of the injection well.

For the sake of comparison, one additional case was simulated, in which porosity and permeability in the reservoir were artificially fixed at their initial values, in this way mechanical effects on the EGS heat extraction are not considered. In Fig. 8 it is reported the time development of fluid mass flow rate obtained with and without mechanical effects. For constant reservoir porosity and permeability the mass flow rate decreases with time, which is a direct consequence of the TH coupling. During the very early stages of the EGS operation, the initial hot water occupying the reservoir pore space is gradually replaced by the injected cold water and the increase in fluid viscosity causes a noticeable decrease of mass flow rate. In time, the heat stored in the rock is gradually extracted by the cold fluid; therefore, the temperature of the fluid passing through the reservoir pore space decreases with time, and its viscosity continuously increases, while the mass flow rate gradually diminishes.

It can be observed in Fig. 8 that mechanical effects have a significant impact, which can even dominate the evolution of the fluid mass flow rate during the early stages of EGS operation. The effective stress to some extent opens up the pore space in the reservoir and explicitly increases the reservoir permeability, as presented in Fig. 7, which, in turn, facilitates the fluid flow. During the

very early stages of the EGS operation, the fluid mass flow rate decreases, but not as much as for the case in which no mechanical effects are considered, and later on, the mass flow rate reaches peak value occurring at an EGS operation of approximately 0.2 years, then gradually decreases due to the gradual increase of fluid viscosity. For most of the EGS operation time of interest, the fluid mass flow rate when mechanical effects are considered is within 30 to 37 kg·s⁻¹ values, much larger than that when the mechanical effects are neglected, which is only around 20 kg·s⁻¹.

Figure 9 reports on the EGS production temperature and heat extraction ratio obtained with and without mechanical effects. The EGS production temperature refers to the volumetric-average fluid temperature at the outlet of production wells and the heat extraction ratio is defined by the following equation:

$$\theta(t) = \frac{\int_0^t (Q_{\text{out}}(t')H_{\text{out}}(t') - Q_{\text{in}}(t')H_{\text{in}})dt'}{\int_{V_h} \rho_s c_{ps} (T_{s,\text{ini}} - T_g)dv} \quad (10)$$

On the right hand side of Eq. (18), the denominator represents the total heat stored in the heat reservoir with reference to the ground temperature, T_g ; the numerator denotes the cumulative heat extracted by the heat transfer fluid, where, Q denotes the fluid mass flow rate, H the specific enthalpy of the hot fluid at the production well outlet; the term $(Q_{\text{out}}(t)H_{\text{out}}(t) - Q_{\text{in}}(t)H_{\text{in}})$ represents the real-time net heat extraction rate; $T_{s,\text{ini}}$ represents the rock initial temperature and V_h the volume of the reservoir.

In Fig. 9, it can be noticed that similar trends are apparent with and without mechanical effects. At the beginning of operation, the production temperature is about 460 K, which corresponds to the average rock temperature in the reservoir, and then decreases with time. The time duration for the production temperature remaining at about 460 K is longer when no mechanical effects are considered as compared to the situation in which they are considered. This is due to the lower fluid mass flow rate of the former one, as shown in Fig. 8, which yields diminished heat extraction rate with consequent lower temperature decrease rate of the rock in the reservoir. Comparison of the heat extraction ratio curves is shown in Fig. 9 and it supports the physical analysis.

A large decrease at the EGS production temperature may lead to significant deviation of the design working conditions of the facility/plant. From this point of view, EGS has a service-time or

lifetime. In previous work [16-17], it was defined the concept of EGS abandonment temperature and EGS lifetime. The EGS abandonment temperature was defined as the EGS production temperature being 10 K lower than its maximum value; the EGS lifetime was specified as the operation time of the EGS until the production temperature reaches the abandonment temperature. Based on these concepts, it can be determined from Fig. 9 that the lifetime for the EGS with mechanical effects is about 6.5 years, while it is about 12 years when these effects are not considered. At the end of EGS operation, the heat extraction ratio values for the two cases are 0.25 and 0.26, respectively. The small difference (0.01) of heat extraction ratio between the two cases, it may be due to the thermal compensation from rocks surrounding the reservoir [16, 17]. In fact when the mechanical effects are absent the operation time is much longer allowing in this way enhanced thermal compensation. Therefore, it is implicit that mechanical effects have little impact on the final heat recovery factor of EGS geothermal resources.

Further, to gain more confidence and establish sufficient fidelity of the numerical model, we did additionally the following two aspects of model validation work besides the grid-independence tests described in Section 3.1. First, we compared the present model results with some published results [3-9, 13-15]. Despite different methods used and different geological conditions considered, all these published works confirmed that the mechanical effects can be very pronounced on the EGS performance; the poroelastic stress and thermoelastic stress component (see e.g. Fig. 2 in Ref. [7], Fig. 10 in Ref. [9]) are qualitatively similar to the results displayed in Fig. 5 of the present work; the obtained curves (see e.g. Fig. 9 in Ref. [24]) of production temperature versus EGS operation time are also qualitatively similar to the results displayed in Fig. 9 of the present work. Second, we compared the model predictions with the measured data from real EGS field tests. Though numerous projects aimed to develop EGS pilot plants have been and are still being conducted around the world, there are generally no measured data about long-term (i.e. 10 or even 20 years) fluid circulation operation. As a compromise, we took the EGS field test data [26] that are only for a few months' heat extraction. The simulated production temperature shown in Fig. 9 can be preliminarily confirmed by the field test data.

3.5 Parametric study of TH effects on the mechanical field

As stated before, a larger pore pressure and temperature difference between the fluid and the rock matrix will increase the porosity and permeability, which will benefit the circulation of the working fluid through the reservoir. However, the pressure and temperature state of the working fluid has considerable influence on its properties. By changing the injection pressure and temperature it is possible bringing together favorable combined effects of the effective stress and fluid properties toward enhanced EGS performance. Therefore, a parametric study for the injection temperature and injection pressure is of interest to investigate their influence on the mechanical field and its eventual feedback on the EGS performance. For the base case the injection temperature, T_{in} , is equal to 343 K, and the injection pressure, p_{in} , 10 MPa. For the injection temperature analysis, the additional values are 323 K and 363 K, respectively. For the injection pressure study, the additional values are 5 MPa and 15 MPa, respectively. Comparison of the effective stress for 0.2 and 5.7 years of the EGS operation is conducted to evaluate the combined effects of injection parameters on the mechanical field. Furthermore, the real-time heat extraction rate, i.e. $(Q_{out}(t)H_{out}(t) - Q_{in}(t)H_{in})$, which is the integrand of the numerator in Eq. (10), will be used to evaluate the combined feedback effects on the EGS performance.

Fig.10 presents the injection temperature effects on the effective stress for 0.2 and 5.7 years of the EGS operation. It can be observed that the effective stress shows four distinct regions for results at both times and for each injection temperature condition. The first region is in the near-region of the injection well, i.e. 0 to 2 m away from the injection well, in which the magnitude of effective stress reaches a peak value and rapidly decreases. The second region, which increases with the time duration of the heat extraction process, shows a relatively smaller temperature gradient than that of the first region. At a time of 0.2 years, the second region covers 2 to 50 m away from the injection well. For 5.7 years of operation, the second region is within 2 to 150 m away from the injection well. Injection temperature effects are more pronounced for 5.7 years of EGS operation than those for an operation of 0.2 years. The third region is adjacent to the second region and extends itself up to 281 m away from the injection well. The fourth region is in the vicinity region of the production well, in which the magnitude of the effective stress rapidly decreases to its minimum value. Due to the cold temperature, the viscosity of the working fluid increases causing a pressure drop along the reservoir. Therefore, in the third and fourth regions,

the magnitude of the effective stress for 5.7 years operation is smaller than that for 0.2 years. It is worth mentioning that as the injection temperature of the fluid is reduced from 363 K to 323 K, the magnitude of the effective stress increases in the second region. In these circumstances, it can be advanced that decreasing injection temperatures lead to increasing reservoir permeability values. Consequently, the reduction of injection temperature will benefit for EGS performance due to the decrease of the reservoir flow resistance.

Fig. 11 shows the combined effects of injection temperature on the real-time heat extraction rate of the EGS. The inset in the Fig. 11 presents the production temperature and relates the lifetime of the EGS to different injection temperatures. The temporal evolution of heat extraction rate shows three distinct stages for each case. During 0 to 1 year of operation, i.e. the first stage, the heat extraction rate shows fluctuation against EGS operation time due to the mass flow rate change. The second stage is associated with the lifetime of the EGS, which differs for each case. The inset in Fig. 11 indicates that the second stage may extend itself from 1 year to 5.2, 6.5 or 8.2 years depending on the value of the injection temperature, i.e., 323 K, 343 K or 363 K, respectively. After the second stage, the heat extraction rate decreases at a fast rate indicating that the EGS is close to the end of its lifetime. To a certain extent, the second stage, in which the heat extraction rate declines but it is relatively stable, determines the EGS performance. It is worth mentioning the heat extraction rate in the second stage increases first and then decreases corresponding to the injection temperature increases from 323 K to 363K.

Fig.12 reports the injection pressure effects on the effective stress for the EGS operation after 0.2 and 5.7 years. In Fig.12 it can be noticed that the magnitude of effective stress increases with the increase of injection pressure. In the near-region of the injection well, the maximum magnitude of the effective stress for 0.2 years of operation reaches the values of -5.6 MPa, -9.5 MPa and -13.2 MPa when the injection pressure is set at 5 MPa, 10 MPa and 15 MPa, respectively. For an injection pressure of 15 MPa, the effective stress, when comparing 0.2 years of operation with 5.7 years, does not show marked difference in trend. However, for the same period, the injection pressure of 5 MPa shows a significant increase of magnitude of the effective stress in the 0-120 m away from the injection well along line AB. This means that a larger injection pressure can yield a relatively stable mechanical field during the EGS operation.

Fig.13 compares the mass flow rate under different injection pressures. For most of the EGS operation time of interest, the fluid mass flow rate takes values around 13 to 15 $\text{kg}\cdot\text{s}^{-1}$, 30 to 37 $\text{kg}\cdot\text{s}^{-1}$ and 62 to 70 $\text{kg}\cdot\text{s}^{-1}$ when the injection pressure is set at 5 MPa, 10 MPa and 15 MPa, respectively. Generally, the mass flow rate of the EGS is directly proportional to the pressure gradient as proposed by Darcy's law. Considering the mechanical effects, the permeability of the reservoir can be enhanced with the increasing injection pressure. Higher values of the reservoir permeability lead to lower values of flow resistance. Thus the mass flow rate can be further increased with a larger injection pressure, and bringing in this way an improved heat extraction rate.

Fig.14 shows the influence of the fluid injection pressure on the heat extraction rate. It can be observed that the temporal evolution of heat extraction rate presents three distinct stages for each case, i.e. the first one is the fluctuation stage, the second one is the relatively stable stage and the third one is the rapid decline stage. For an injection pressure of 15 MPa, the heat extraction rate shows very good performance during the first and second stage; however, the performance decreases at very fast pace during the third stage.

3.6 Parametric study of rock-fluid local thermal non-equilibrium effects

Rock-fluid heat exchange in the heat reservoir of the EGS is very important to the mechanical field and EGS heat extraction. In terms of the local thermal non-equilibrium model, rock-fluid heat exchange is governed by the temperature difference, the rock-fluid convective heat transfer coefficient (h) and the specific surface area of the fractures (a). In this work, the product of h and a is considered to be a single parameter, i.e. the volumetric heat transfer coefficient (ha), to investigate the local thermal non-equilibrium effects on the mechanical field and EGS performance. In practice, the parameter ha depends on the fluid velocity in the fracture, the fluid properties, the flow regime, and the microstructure of the fracture. The determination of the parameter ha can be obtained experimentally; to obtain it using numerical simulations is rather involved in terms of modeling and it is very demanding in terms of computing resources. In this work ha is specified as constant value and, for the purpose of the analysis, ha takes three different values, namely: 0.1, 1.0 and 10.0 $\text{W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$, respectively.

Fig.15 depicts the profiles of the effective stress along the line AB for 0.2 and 5.7 years of EGS operation with different ha parameters. Compared with the base case ($ha = 1.0 \text{ W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$), the effective stress for the smallest volumetric heat transfer coefficient ($ha = 0.1 \text{ W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$) shows lower absolute value in each location for 0.2 years of EGS operation; however, for 5.7 years of operation, this behavior is only apparent for the distance 0-100 m away from the injection well along line AB. For small values of ha , rock-fluid heat exchange rate is reduced and it increases the time for the thermal front to penetrate the rock matrix. Therefore, the thermal gradient in the rock will be small and consequently, the thermoelastic stress will be equally small. By contrast, however, only a small difference of the effective stress can be observed between the base case and the case with the value of ha equal to $10.0 \text{ W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$, which may lead to the conclusion that for values of ha greater than $1.0 \text{ W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$, the non-equilibrium rock-fluid heat exchange will converge to that with thermal equilibrium.

Fig. 16 compares the heat extraction rate as a function of the value of the parameter ha along the EGS operation time. Once again the selected values of ha are: 0.1, 1.0 and $10.0 \text{ W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$. The smallest value of ha yields the lowest performance in terms of heat extraction rate of the EGS operation, when compared with the other two values of ha ; the peak value of heat extraction rate is approximately 66 MW at 1.5 years of EGS operation. For the two other values of ha , $1.0 \text{ W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$ and $10.0 \text{ W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$, respectively, the results are practically indistinguishable, which indicates that for this range of values of ha , this parameter has little or no influence upon the heat extraction rate; only a very minor increment of heat extraction rate can be noticed under 0.3 years of EGS operation, when the value of ha increases from 1.0 to $10.0 \text{ W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$, which is in full agreement with the results reported in Fig. 15.

4. Summary and Conclusions

A transient, three-dimensional numerical model was developed to simulate and analyze the EGS heat extraction process. This model handles in a novel and consistent formulation describing the fully coupled thermal, hydraulic and mechanical (T-H-M) processes in EGS subsurface reservoir during heat extraction. The main features of the model are: i) Local thermal non-equilibrium between rock matrix and fluid flowing in the reservoir is considered, enabling simulation of local convective heat exchange in EGS subsurface reservoir; ii) Temperature- and

pressure- dependent thermophysical properties of water are implemented allowing for the bi-directional coupling of T and M processes; and iii) A thermo-poroelastic model is employed, which relates the effective stress in the rock matrix to temperature and fluid pressure, and in return, adjusts local porosity and permeability in the reservoir in terms of the calculated temporal effective stress field. In addition, case studies for an idealized EGS were conducted to demonstrate the capability of the developed model and to provide for further understanding of the intervening THM coupling mechanisms during EGS heat extraction.

The stress triggered by fluid pressure is found to be compressive and confined to the near-region of the injection well; the thermal stress is tensile and to some extent is also concentrated in the vicinity of the injection well; however, its distribution region increases toward the production well while the heat extraction process progresses. The temperature difference between rock matrix and heat transmission fluid is not the only driving force in what concerns heat extraction from heat reservoir; thermal gradient on the rock yields the formation of thermal stress, which will affect the permeability in the reservoir and its heat extraction. This mechanical effect on EGS heat extraction is found to be very pronounced. An increase in injection pressure leads to increased fluid mass flow rate as a result of higher pore space in the reservoir due the increase of the stress state. In this way, the heat extraction rate is further enhanced but, as expected, since the heat reservoir is a finite resource, the EGS lifetime is shortened. At the end of EGS operation, based on the results for the heat extraction ratio, mechanical effects only have a minor impact on the heat recovery factor of EGS geothermal resources.

By changing the injection pressure and temperature, the model can predict well the combined effects of the effective stress and the fluid properties on the EGS heat extraction rate. A low injection temperature and a high injection pressure can yield a increase at the magnitude of the negative effective stress; in this way, the mass flow rate and the heat extraction rate can be enhanced due to the corresponding enlargement of the heat reservoir permeability. However, the viscosity of the working fluid can significantly increase when temperature decreases and pressure increases. Taking into consideration these opposing effects together, the developed model will make viable the optimization of the injection temperature and pressure.

The influence of the volumetric heat transfer coefficient, ha , was analyzed in what concerns the EGS heat extraction. A small value of ha reduces the heat exchange between the rock and the fluid. It also reduces the magnitude of the effective stress and brings limited enlargement of the porosity and permeability of the heat reservoir.

Future work to make the model a viable tool to geothermal engineering applications will require a well-planned benchmarking program using actual EGS heat extraction operations. To this purpose it is envisaged that future enhancements of the model will include: i) Extension of the present reservoir modeling to consider heterogeneous, anisotropic porous medium; ii) Development of a chemical module (C) to study the effects of chemical actions (e.g. mineral deposition and dissolution) on the EGS heat extraction performance, which will be coupled to the present THM model yielding a THMC model; and iii) The capability of handling phase change and multiphase flow, in addition to the existing single phase flow, will broaden the spectrum of application.

Nomenclature

a	specific surface area of the fractures (m^2)
B	Rock bulk modulus (GPa)
c_p	heat capacity ($\text{J}\cdot\text{kg}^{-1}\cdot\text{K}^{-1}$)
$\mathbf{g}$	acceleration of gravity ($\text{m}\cdot\text{s}^{-2}$)
H	specific enthalpy ($\text{J}\cdot\text{kg}^{-1}$)
ha	volumetric heat transfer coefficient ($\text{W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$)
k	thermal conductivity ($\text{W}\cdot\text{m}^{-1}\cdot\text{K}^{-1}$)
K	permeability (m^2)
p	pressure (Pa)
Q	mass flow rate ($\text{kg}\cdot\text{s}^{-1}$)
t	time (s)
T	temperature (K)
$\mathbf{u}$	velocity vector ($\text{m}\cdot\text{s}^{-1}$)
x	horizontal axis in Cartesian coordinates
y	vertical axis in Cartesian coordinates
z	horizontal axis in Cartesian coordinates

Greek symbols

α	Biot's coefficient
β	rock linear thermal expansion
ρ	density ($\text{kg}\cdot\text{m}^{-3}$)
ε	porosity
μ	viscosity ($\text{m}^2\cdot\text{s}^{-1}$)
θ	heat extraction ratio
Φ	generic variable
σ_m	mean total stress (Pa)
σ'	effective stress (Pa)
ν	rock Poisson's ratio

Subscripts/superscripts

eff	effective
f	fluid
in	injection
ini	initial
s	solid or rock
0	initial or values under a zero effective stress
r	values under a reference high effective stress

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Fig. 1 Geometry and mesh system. (a) Geometry and geometrical dimensions of the considered quintuplet EGS; (b) mesh system of the simulated geometry.

Fig. 2 Rock temperature distribution in the heat reservoir.

Fig. 3 Pore pressure distribution in the heat reservoir.

Fig. 4 Mean total stress distribution in the heat reservoir.

Fig. 5 Poroelastic and thermoelastic stress in the reservoir after 5 years of EGS operation.

Fig. 6 Rock and fluid temperature and thermoelastic stress along line AB after 5 years of EGS operation.

Fig. 7 Effective stress (a), porosity (b) and permeability (c) in the reservoir after 5 years of EGS operation.

Fig. 8 Fluid mass flow rate during EGS operation with and without mechanical effects.

Fig. 9 Production temperature and heat extraction ratio with and without mechanical effects.

Fig.10 Injection temperature effects on effective stress.

Fig.11 Injection temperature effects on heat extraction rate.

Fig.12 Injection pressure effects on effective stress.

Fig. 13 Effect of the injection pressure on the mass flow rate

Fig.14 Effect of the injection pressure on the heat extraction rate

Fig.15 The effect of the parameter ha on the effective stress

Fig.16 Effect of the parameter ha on the heat extraction rate

Table 1 Summary of the governing equations.

Equation#	Φ	Γ_Φ	S_Φ
Eq.(1)	ρ_f	0	0
Eq.(2)	$\rho_f \mathbf{u}$	$\varepsilon \mu / \rho_f$	$-\nabla(\varepsilon^2 p) - \varepsilon^2 \frac{\mu}{K} \mathbf{u} + \varepsilon^2 \rho_f \mathbf{g}$
Eq.(3)	$\rho_s c_{ps} T_s$	$\lambda_s / (\rho_s c_{ps})$	$\frac{\partial[(2\varepsilon - 1)\rho_s c_{ps} T_s]}{\partial t} - ha(T_s - T_f)$
Eq.(4)	$\rho_f c_{pf} T_f$	$\lambda_f / (\rho_f c_{pf})$	$ha(T_s - T_f)$
Eq.(5)	σ_m	$3(1-\nu)/(1+\nu)$	$\frac{2\alpha(1-2\nu)}{(1+\nu)} \nabla^2 p + \frac{6\beta B(1-2\nu)}{(1+\nu)} \nabla^2 T - \nabla \cdot \mathbf{F}$

Table 2 Model parameters

Parameter	Value
Rock density, ρ_s ($\text{kg}\cdot\text{m}^{-3}$)	2650.0 ^[7]
Rock heat capacity, c_{ps} ($\text{J}\cdot\text{kg}^{-1}\cdot\text{K}^{-1}$)	1000.0 ^[7]
Rock thermal conductivity, λ_s ($\text{W}\cdot\text{m}^{-1}\cdot\text{K}^{-1}$)	2.4 ^[8]
Rock Poisson's ratio, ν	0.2 ^[8]
Rock bulk modulus, B (GPa)	9.3 ^[8]
Rock linear thermal expansion, β	1.15×10^{-6} ^[8]
Biot's coefficient, α	1.0 ^[5]
Initial porosity, ε_0	0.01 ^[16]
Porosity under a reference high normal effective stress, ε_r	0.009 ^[5, 13]
Initial permeability, K_0 (m^2)	1.0×10^{-14} ^[16]
Volumetric heat transfer coefficient, ha ($\text{W}\cdot\text{m}^{-3}\cdot\text{K}^{-1}$)	1.0 ^[16]