Geothermics 61 (2016) 46–62

Contents lists available at ScienceDirect

Geothermics

journal homepage: www.elsevier.com/locate/geothermics

Thermal drawdown-induced flow channeling in a single fracture in EGS

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ARTICLE INFO

Article history:
Received 9 June 2015
Received in revised form
11 November 2015
Accepted 10 January 2016
Available online 28 January 2016

Keywords:
EGS
Thermal drawdown
Flow channeling
Aperture heterogeneity
THM coupling
GEOS

ABSTRACT

The evolution of flow pattern along a single fracture and its effects on heat production is a fundamental problem in the assessments of engineered geothermal systems (EGS). The channelized flow pattern associated with ubiquitous heterogeneity in fracture aperture distribution causes non-uniform temperature decrease in the rock body, which makes the flow increasingly concentrated into some preferential paths through the action of thermal stress. This mechanism may cause rapid heat production deterioration of EGS reservoirs. In this study, we investigated the effects of aperture heterogeneity on flow pattern evolution in a single fracture in a low-permeability crystalline formation. We developed a numerical model on the platform of GEOS to simulate the coupled thermo-hydro-mechanical processes in a penny-shaped fracture accessed via an injection well and a production well. We find that aperture heterogeneity generally exacerbates flow channeling and reservoir performance generally decreases with longer correlation length of aperture field. The expected production life is highly variable (5 years to beyond 30 years) when the aperture correlation length is longer than 1/5 of the well distance, whereas a heterogeneous fracture behaves similar to a homogeneous one when the correlation length is much shorter than the well distance. Besides, the mean production life decreases with greater aperture standard deviation only when the correlation length is relatively long. Although flow channeling is inevitable, initial aperture fields and well locations that enable tortuous preferential paths tend to deliver long heat production lives.

1. Introduction

Engineered (or enhanced) geothermal systems (EGS) are promising energy resources with an enormous potential for base-load electricity generation (Tester et al., 2006; Lund et al., 2011; Bertani, 2012; Jung, 2013). Unlike conventional hydrothermal energy, EGS is not limited to locations with abundant water supply and high-conductivity formations. Engineering measures such as hydraulic fracturing and hydraulic shearing provide the opportunity to extract heat from originally low-permeability crystalline formations by creating new fractures and/or enhancing the permeabilities of natural fractures (Brown and Duchane, 1999; Tenma et al., 2008; Brown, 2009). Water circulation in an EGS reservoir can be dominated by flow in a single fracture/fault (Brown, 1997; Brown and Duchane, 1999; Chopra and Wyborn, 2003; Baisch et al., 2006; Brown, 2009; Llanos et al., 2015) or through an interconnected fracture network (Koh et al., 2011; Genter et al., 2012, 2013). In either case, the flow pattern as well as its evolution along an individual fracture and the heat exchange between the working fluid and the rock surrounding this fracture play a fundamental role in heat production.

Fluid flow and heat exchange closely interact during EGS heat production. Because heat is transferred from the rock surrounding the fracture to the production well(s) by flowing fluid, only the portion of fracture that carries flow provides effective heat exchange surface area. It is therefore highly desirable to have flow spreading over a large area of the fracture surface. However, spatially heterogeneous fractures are ubiquitous in geologic formations (Neretnieks, 1987; Méheust and Schmittbuhl, 2000; Kosakowski et al., 2001) and fluid flow in a fracture with aperture heterogeneity tends to be channelized along a few preferential paths (Tsang and Tsang, 1989). The rock body near the preferential paths tends to cool faster than other regions do, and the cooled rock body develops thermal stress that reduces the effective compressive stress acting on the preferential flow paths and thereby increases the fracture aperture. The increase of aperture, in turn, makes the flow even more channelized along these preferential paths. In the present study, the term "flow channeling" refers

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http://dx.doi.org/10.1016/j.geothermics.2016.01.004
0375-6505/

to the phenomenon or process of the preferential paths carrying an increasing portion of the flow. This mechanism is expected to reduce heat exchange efficiency and cause rapid heat production deterioration.

Numerous studies have shown evidence for fracture aperture/transmissivity evolution due to the thermo-hydro-mechanical (THM) processes in EGS reservoirs dominated by either a single fracture/fault or a fracture network (Kolditz and Clauser, 1998; Parker, 1999; Tenma et al., 2008). For example, Bower and Zyvoloski (1997) coupled stress to a flow and heat transfer model and found that the fracture flow increases due to further opening of a single fracture in the Fenton Hill hot dry rock reservoir. Danko and Bahrami (2012) used a THM model to simulate the heat production in two EGS reservoirs at Fenton Hill and Desert Peak, each of which was modeled to be dominated by a single fracture. They observed that only the aperture near the central part of the fracture increases over time. Hicks et al. (1996) simulated the THM processes in a fractured rock and observed a decreasing injection pressure and an increasing water recovery percentage, indicating an increase in the overall permeability. Koh et al. (2011) also found great enhancement of injectivity at a given pressure drop over 10 years in naturally fractured rock. Fu et al. (2015) conducted THM coupled simulations of heat production in fracture networks and observed that the flow inevitably becomes more concentrated into a few channels during heat production. Although THM processes significantly affects heat production in those studies, the quantitative effects of spatially heterogeneous fracture aperture on flow channeling remains poorly understood.

A number of studies, such as Taron and Elsworth (2009), Pandey et al. (2014), Ameli et al. (2014), Deng et al. (2015), etc. have shown that geochemical reactions could alter permeability/transmissivity of fractures and porous media under certain conditions. However, the current study focuses on THM processes and does not consider geochemistry for two reasons: First, quartz, the main component of crystalline rocks (the host formations of most EGS), reacts with water very slowly and the effects of water-quartz reaction on aperture alteration are expected to be negligible within the typical lifespan of EGS. Second, the THM process investigated herein alone can have very significant effects on EGS performance and it is more appropriate to study the effects of geochemistry in separate work.

The present study develops a numerical model that fully couples the THM processes during heat production and quantitatively investigates the effects of spatial heterogeneity in aperture on flow channeling in a single planar fracture in an EGS reservoir. We especially focus on how the probability distribution and spatial autocorrelation characteristics of the aperture field affect the reservoir performance. The results are directly useful for EGS reservoirs dominated by a single fracture/fault, and they also provide useful insights into the fundamental behavior of individual fractures in a fracture network.

2. Coupled THM model

2.1. Overview of the model

We developed a new numerical model on GEOS, a high performance computing (HPC) platform developed at the Lawrence Livermore National Laboratory (LLNL) (Fu and Carrigan, 2012; Settgast et al., 2012; Fu et al., 2013), to simulate the coupled THM processes in the heat production stage of an EGS reservoir. The essential processes/mechanisms (Pruess, 1990; Hayashi et al., 1999; McDermott et al., 2006; Guo et al., 2015) involved in the flow channeling phenomenon include:

1. Fluid flow along a fracture and in the rock matrix, as well as its evolution as the aperture/permeability field changes;
2. Convective heat transfer associated with the fluid flow along the fracture, conductive heat transfer in the rock matrix, and heat exchange between the working fluid and the surrounding rock body;
3. The change of total stress caused by the non-uniform cooling of the rock body; and
4. The evolution of the local fracture aperture as the effective stress changes.

The first two processes are simulated by a combined flow and heat transfer solver developed in GEOS, as shown in Fig. 1 and elaborated on in Section 2.2. Thermal stress is calculated by a thermo-mechanical solver and the total stress tensor of each rock matrix element is updated accordingly as briefly described in Section 2.3. Section 2.4 presents the procedure of updating the fracture aperture field based on the fluid pressure and stress change along the fracture in the reservoir.

2.2. Flow and heat transfer in fracture and matrix

The flow and heat transfer solver combines fluid flow and heat transfer in both fractures and rock matrix. We use a finite volume formulation to solve the independent state variables, namely fluid pressure P and temperature T, for 3D 8-node hexahedron elements. The coupled single-phase flow and heat transfer in porous medium are governed by the principle of mass and energy conservation. The mass conservation equation for compressible fluid is

$$\frac{\partial(\rho\phi)}{\partial t} + \nabla\cdot(\rho\boldsymbol{v}) = \Gamma \quad (1),$$

where ρ is the fluid density; φ is the rock porosity; t is time; $\mathbf{v}$ is the fluid velocity vector; and Γ is a source/sink term. According to Darcy's law, fluid velocity vector v is calculated as

$$\boldsymbol{v} = -\frac{\boldsymbol{k}}{\mu}(\nabla\mathrm{P} - \rho\mathbf{g}) \quad (2),$$

where $\mathbf{k}$ is the intrinsic permeability tensor of the rock matrix; μ is the fluid dynamic viscosity; and $\mathbf{g}$ is the gravity acceleration vector. The current study assumes the permeability of rock matrix to be isotropic, so the permeability tensor is reduced to the permeability scalar k. Substituting Eq. (2) into Eq. (1) yields

$$\frac{\partial(\rho\phi)}{\partial t} - \nabla\cdot\left[\rho\frac{k}{\mu}(\nabla\mathrm{P} - \rho\mathbf{g})\right] = \Gamma \quad (3).$$

Fluid density ρ depends on fluid pressure and temperature, as approximated by the following analytical function

$$\rho = \rho_r e^{\left[\beta_f(P-P_r)+\alpha_f(T-T_r)\right]} \quad (4),$$

where ρ_r, P_r, T_r, β_f, and α_f are the fluid density, pressure, temperature, fluid compressibility, and fluid thermal expansion coefficient, respectively, in a known reference state.

The fracture, while hydraulically conductive, is mechanically closed under the high *in situ* compressive stress assumed in this study. GEOS has the capability to represent fractures using planar "face element" embedded in the solid mesh as described in Guo et al. (2015). However this treatment is computational expensive and is unnecessary for the current study due to the simple geometry that we investigate. The fracture in the present model is represented by a very thin layer (2 mm thick) of porous medium. When Eq. (3) is applied to fracture grid elements, the porosity is set as unity and the effective permeability k_f is calculated according to the cubic law (Berkowitz, 2002) as

$$k_f = \frac{A^3}{12H} \quad (5),$$