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Numerical modeling of injection, stress and permeability enhancement during shear stimulation at the Desert Peak Enhanced Geothermal System

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ABSTRACT

Creation of an Enhanced Geothermal System relies on stimulation of fracture permeability through self-propping shear failure that creates a complex fracture network with high surface area for efficient heat transfer. In 2010, shear stimulation was carried out in well 27-15 at Desert Peak geothermal field, Nevada, by injecting cold water at pressure less than the minimum principal stress. An order-of-magnitude improvement in well injectivity was recorded. Here, we describe a numerical model that accounts for injection-induced stress changes and permeability enhancement during this stimulation. We use the coupled thermo-hydrological–mechanical simulator FEHM to (i) construct a wellbore model for non-steady bottom-hole temperature and pressure conditions during the injection, and (ii) apply these pressures and temperatures as a source term in a numerical model of the stimulation. A Mohr–Coulomb failure criterion and empirical fracture permeability is developed to describe permeability evolution of the fractured rock. The numerical model is calibrated using laboratory measurements of material properties on representative core samples and wellhead records of injection pressure and mass flow during the shear stimulation. The model captures both the absence of stimulation at low wellhead pressure (WHP ≤ 1.7 and ≤ 2.4 MPa) as well as the timing and magnitude of injectivity rise at medium WHP (3.1 MPa). Results indicate that thermoelastic effects near the wellbore and the associated non-local stresses further from the well combine to propagate a failure front away from the injection well. Elevated WHP promotes failure, increases the injection rate, and cools the wellbore; however, as the overpressure drops off with distance, thermal and non-local stresses play an ongoing role in promoting shear failure at increasing distance from the well.

1. Introduction

Shear stimulation is one method for improving the permeability of naturally fractured rock to create an Enhanced Geothermal System (EGS). The approach is an evolution of the idea that, over geological time, shear slip is necessary to create and maintain the conductivity of naturally-occurring fractures and faults.[1,2] EGS stimulations are designed to accelerate this process – inducing shear failure on existing fractures – through injection of cold water, thereby elevating fluid pressure inside the fractures and promoting cooling and thermal contraction of the fracture walls. Frictional failure induced by these fluid pressure and stress changes combined with mismatch of asperities during shearing results in self-propped, dilatant fractures that are better able to conduct fluids. Additionally, creation of new flow paths grows the fracture network, increasing the volume of rock amenable to heat extraction.

The success of this approach relies on the existence of hot rocks containing fractures oriented for shear failure, ambient differential stress large enough that the fractures are already near frictional failure, and material and mechanical properties conducive to shear-enhanced dilation.[3] Such conditions are frequently found in or adjacent to natural hydrothermal systems,[4,5] which are often associated with regions of tectonic extension (leading to critically stressed fractures under low confining stress) and lithospheric thinning (for high crustal temperatures at drillable depths). In addition, fluid–rock interactions in natural hydrothermal systems

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can either promote shear-enhanced dilation through rock silicification and embrittlement,[6] or inhibit dilation through clay alteration within fractures, favoring ductile deformation.[5,7] For these reasons, the margins of natural hydrothermal systems are convenient test beds for EGS shear stimulation operations, such as at Desert Peak, Nevada,[8] Geysers, California,[9] and Ngatamariki, New Zealand.[10]

Shear stimulation is also utilized in conventional hydrothermal settings, for example, New Zealand[10] and the Philippines.[11] It has been noted that the injectivity of wells used for reinjection of produced fluids generally increases with continued use. As the reinjected brine is often cooler than the formation into which it is being injected, improvements to injectivity are in some cases attributed to thermoelastic contraction of rock mass around the well, leading to an increase in fracture apertures under decreasing normal stress. This elastic mechanism is in marked contrast to the shearing-induced changes in permeability discussed above, and is consistent with reports of injectivity decline when reinjection is halted or a well is subsequently produced.[10]

Numerical simulators that account for the coupled thermal-hydrological–mechanical (THM) processes involved in an EGS shear stimulation are becoming increasingly widespread, and include FEHM,[12] TOUGH2-FLAC3D,[13] OpenGeoSys[14,15] and FALCON.[16] In addition to accounting for two-phase fluid flow and heat transfer, these codes solve force balance equations for stress and deformation on a continuum representation of the matrix–fracture domain. It is particularly important to capture thermoelastic and poroelastic stress changes induced in the rock matrix when cold water is injected at elevated pressure into a hot reservoir; these induced stresses can lead to permeability enhancement by promoting frictional failure or elastic fracture dilatation, compounding the direct effects of changes in effective normal stress on fracture permeability.

To model properly injectivity enhancement during stimulation requires relationships for the change in permeability in response to the perturbed stress state, including both elastic and inelastic effects. These relationships include elastic opening of fracture apertures through reduction of effective normal stress by fluid pressurization[17] or changes in thermoelastic stress due to cooling[10]; in both cases, injectivity gains can be lost when the reservoir reverts back to its original state. Alternatively, plastic deformation upon mechanical failure can lead to permanent permeability gains. Several conceptual models and mathematical formulations have been proposed for stress-dependent fracture permeability during fluid pressurization. These models include thermo-poroelastic deformation of a regular array of fractures,[18] aperture enhancement through fracture-propagation and shear-dilation of a statistically representative fracture population,[19] a crack-tensor approach that yields upscaled permeability and elastic properties based on Mohr–Coulomb failure and dilation of sub-grid-scale fractures,[20] and permeability as a function of the normal-stress dependent fracture aperture.[21]

In this paper, we present a THM numerical modeling study of the shear stimulation of well 27-15 in the Desert Peak geothermal field, Nevada. Similar to the crack-tensor approach of Rutqvist et al.[20] we use sub-grid-scale fracture populations that are assessed for Mohr–Coulomb failure, with permeability enhanced according to an empirical relationship based on laboratory shearing experiments. In Section 2, we discuss the tectonic and structural setting at Desert Peak, and summarize the comprehensive site characterization studies that reveal the distribution of pre-existing fractures, the orientations and magnitudes of ambient stresses, and the lithological and mechanical properties of the stimulated formations. We also summarize key aspects of the multi-staged shear stimulation[3,8] carried out at this site. In Section 3, we describe the construction of a numerical wellbore model used to determine non-steady bottom-hole temperature and pressure conditions during this shear stimulation. In Section 4, we describe construction of the shear stimulation model including the relationship for stress-dependent permeability and a time-varying injection source term informed by the wellbore model. In Section 5, we present the calibrated stimulation model for Desert Peak EGS well 27-15 and discuss spatial and temporal evolution of the stimulated region along with model sensitivities. The coupled THM modeling study presented here builds on earlier work by Kelkar et al.[22] and Dempsey et al.[23,24]

2. The Desert Peak EGS demonstration project

2.1. Site characterization

Natural hydrothermal systems in the Great Basin of the western United States generally are found within several northeast trending belts that are aligned orthogonal to the direction of extension.[25] These regions localize extensional deformation and crustal thinning, which opens pathways for deep fluid circulation and advective heat transfer to shallower depths. The Hot Spring Mountains are located in one of these belts – the Humboldt Structural Zone – and host three major geothermal fields: Desert Peak, Brady's and Desert Queen. Desert Peak is a high-enthalpy, blind geothermal system with no active hot springs or fumaroles. The field is associated with a left step in the NNE-trending, WNW-dipping Rhyolite Ridge normal fault zone.[25] The orientation and mode of faulting are consistent with regional NW-directed extension.[26]

Geothermal power is generated from fluids produced in the southwest region of the Desert Peak field, with additional pressure support for the reservoir supplied by reinjection into several wells northeast of the main production area (Fig. 1). When drilled, well DP 27-15 exhibited poor injectivity and was selected for EGS stimulation over three potential depth intervals.[27] The uppermost of these zones was selected for an initial (shallow) stimulation, extending from the casing shoe at 915 m to the top of a temporary cement plug at 1065 m. This cement plug was later drilled out and in order to allow the entire open-hole interval of 27-15 to be stimulated in the final phase of the Desert Peak EGS project. This latter phase of the project will not be discussed further in this paper. The shallow stimulation consisted of three phases[8]: (i) shear stimulation by injection of cold-water at pressure less than the minimum horizontal principal stress, σ_h; (ii) chemical stimulation by injection of acid; and (iii) a controlled hydraulic fracturing phase. Only the shear stimulation phase is modeled here; a discussion of the other shallow stimulation phases is presented in Chabora et al.[8] Prior to this stimulation, comprehensive borehole geophysics, tracer studies, laboratory testing and seismological studies were undertaken to create a geomechanical and hydrologic model of the site[3,7,27–29]

Shear stimulation relies on the triggering of self-propping shear failure on pre-existing fractures. In designing and modeling the effects of a shear stimulation, it is necessary to know the pre-existing fracture distribution, including orientations, density and frictional properties, and the magnitude and orientation of the in-situ principal stress fields acting on those fractures. Davatzes and Hickman[27] undertook a fracture characterization study in well 27-15 using borehole image logs collected to depths of almost 1700 m. They recorded extensive drilling-induced tensile failure that indicated an orientation for σ_V of $114 \pm 17°$, consistent with the NNE trend of surface normal faulting.[30] Temperature gradient anomalies from precision temperature logs were also used to identify zones of fluid flow, interpreted to correspond to intervals of slightly elevated fracture permeability.