

Constant viscosity versus Temperature-Dependent viscosity: Consequences for the Numerical Modeling of Enhanced Geothermal Systems

Esuru R. Okoroafor*, Adam J. Hawkins and Roland N. Horne

Department of Energy Resources Engineering, Stanford University, Stanford, CA 94305

*ritaok@stanford.edu

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ABSTRACT

In an Enhanced Geothermal System (EGS), channeled-flow conditions in the subsurface can lead to premature thermal breakthrough due to the concentration of circulating fluids through “channels” of relatively low heat transfer area. Therefore, adequate modeling of EGS thermal performance requires proper accounting of spatial aperture variations within the two-dimensional plane of one or more target fractures. In the case of cold fluid injection, poroelastic effects and nonuniform temperature distributions can cause opening/closure of the fluid-filled aperture which can further affect thermal performance. In this study, a numerical experiment investigated the impact of thermo-hydro-mechanical coupling on EGS thermal performance. These effects were investigated for a single, heterogeneous fracture of nonuniform aperture and the evolution of the fracture aperture during cold water injection was simulated. In one scenario, constant water viscosity was assumed for the duration of the simulation while in another scenario, the variation of viscosity with changes in temperature was considered. The objective was to examine the impact of constant viscosity assumption in modeling EGS.

From the study, it was observed that spatial aperture variations worsen flow channeling due to the thermal stresses and thus the predicted thermal performance of the EGS was impaired compared to the case where the thermal stresses were not taken into consideration. Moreover, the degree of impairment in the predicted EGS thermal performance was more significant in the case with temperature dependent viscosity than in the case of constant viscosity.

1. INTRODUCTION

An Enhanced Geothermal System (EGS) allows heat extraction from fractures by conductive thermal recharge. Heat extraction is achieved by first creating permeable pathways in the form of induced fractures within the rock body, then injecting relatively cold fluids (e.g. liquid water) that keeps the fracture(s) open and collects thermal energy from the surrounding rock matrix. One or more production wells return heated water to ground surface for use as a working fluid for electricity generation or for direct-use heating/cooling (absorption chillers). Fractures are initiated by hydraulic stimulation where new tensile fractures propagate from the borehole once injection fluid pressures exceed failure limits of the rock and/or shear is induced along preexisting fractures (e.g., Gischig and Preisig, 2015; McClure and Horne, 2014). With hydroshearing being the predominant mechanism for enhancing the permeability EGS according to Gischig and Preisig, (2015), the fracture(s) tend to be self-propped due to mismatched asperities across the two fracture surfaces. Several studies (e.g., Abelin, et al., 1991; Hakami and Larsson, 1996; Tsang and Neretnieks, 1998; Tester, et al., 2006; Watanabe, et al., 2008; Mattson, et al., 2018; Co, Pollard and Horne, 2017) allude to the spatial variation of fracture surfaces across different scales, and have demonstrated that variation in fracture aperture can lead to flow channeling. In an EGS, cold water is circulated through one or more fractures in the hot rock reservoir and fluid collection at one or more producers returns the heated working fluid to ground surface. Therefore, heat is recovered only across the effective heat transfer area available between injectors and producers. Under channeled flow conditions, relatively reduced heat transfer area can lead to inadequate heat transfer efficiency (e.g., Neuville, et al., 2010) and, as a consequence, cause premature thermal breakthrough and reduced energy recovery (Co, 2017; Hawkins, et al., 2017, 2018).

From the foregoing, it can be seen that flow channeling has the ability to impact the energy recovery of EGS. Thus, it becomes necessary to model channeling accurately for better estimation and forecasting of thermal performance. The transport mechanisms in this system consist of thermal conduction by contact between the bulk rock matrix and fracture fluids, convection (transport of heat within the fluid), and mass transport in the fluid (from injection and extraction – as the cold or hot fluid is in motion). Studies have shown that in systems where cold water is injected into hot rocks, some degree of thermal stress occurs, impacting the fracture aperture and permeability. These findings are highlighted below.

McDermott, et al. (2006) investigated the influence of thermal-hydraulic-mechanical (THM) coupling on the heat extraction from fractured crystalline rocks using an experimentally validated geomechanical model. Their study indicated that preferential fluid flow paths (i.e., “short-circuits”) may develop, depending on the mechanical and thermal stress releases that occur during exploitation of these systems.

Ghassemi and Govindarajan (2007) studied thermally-induced aperture changes in a one-dimensional system. They investigated the temporal variation of fracture aperture in response to the individual and combined effects of thermal stress and silica dissolution/precipitation. In their work, the aperture change of a single fracture within an infinitely large reservoir was calculated and compared with numerical results. The results showed that, for lower initial fracture apertures, the significant increase in fracture permeability and the associated pressure drop at the injection point were mostly attributable to thermoelastic effects, while the increase in fracture aperture near the production well was mainly the result of silica dissolution. On the other hand, for larger initial apertures, the effects of silica precipitation/dissolution were minimal and thermoelastic effects were prevalent. However, in their study, spatial variations in fracture aperture were not taken into account.

Ghassemi et al. (2008) used analytical methods to investigate a poro-thermoelastic analysis of the effects of heat extraction on fracture aperture. The results of their study indicated that fracture aperture increases near the injection point due to thermally induced stresses and causes a reduction in fluid injection pressure. The thermoelastic effects dominated near the injection point when compared to those of poroelasticity.

Guo, et al. (2016) developed a numerical model that fully couples the THM processes during heat production and quantitatively investigated the effects of nonuniform (i.e., heterogeneous) aperture on flow channeling in a single planar fracture. The aperture was treated as an autocorrelated random field across the fracture plane. They used a horizontal penny-shaped fracture in a large body of low-permeability hot crystalline rock. Fluid density and viscosity were assumed to be constant. Their study suggests that thermal breakthrough occurs earlier when accounting for thermal stresses.

Because the transport mechanism in an EGS may result in thermoelastic behavior, it is important to consider geomechanics in modeling heat extraction from such systems. Consequently, this study aimed at employing a numerical approach to investigate the stress-dependent behaviors of fractured geothermal systems and to quantify the resulting impacts on thermal performance. This involved a THM coupling of the processes that govern heat extraction. A single fracture was considered with spatial aperture variations in a hypothetical EGS doublet system. The evolution of the fracture aperture as a function of effective stress was simulated and the subsequent impacts on heat transfer investigated. In addition, the direction of flow relative to the fracture shear offset and how it impacts the thermal stress and ultimately the thermal performance of EGS were examined. The analysis was done for a scenario with constant viscosity and another with temperature-dependent viscosity for the duration of the simulation.

2. THERMO-HYDRO-MECHANICAL COUPLING

2.1 Coupling Methodology

The hypothetical EGS reservoir includes a single injector/producer well-pair with working-fluid circulation through a single fracture contained within hot, impermeable rock. Relatively cold injectate is heated by the surrounding rock and then recovered at a single production well. Thermal stresses accumulate as the target fracture experiences nonuniform cooling induced by circulation through the heterogeneous plane. The changes in the effective stress consequently result in opening/closing of fracture apertures.

In order to model these mechanisms, the thermo-hydraulic process is coupled with the geomechanical process. This was achieved using the software tools ECLIPSE and VISAGE. The thermo-hydraulic process of EGS heat extraction was modeled using ECLIPSE thermal compositional numerical simulator. ECLIPSE is a finite-difference simulator and was run here in the fully implicit mode. The thermodynamic properties of water and steam are based on the International Association for the Properties of Water and Steam (IAPWS-IF97) (Wagner, et al., 2000) using the keyword: THSTT97. Cartesian block-center geometry in three dimensions was used and simulator results have been verified for geothermal applications by Stacey and Williams (2017) and Okoroafor and Horne (2018).

VISAGE is a general solver for finite-element geomechanics (Schlumberger, 2017). In coupling the two simulators, the VISAGE model can be thought of as modelling along the edges of the grid cells while ECLIPSE models the flow through the cells. When fluid flows through the grid of ECLIPSE, the pore pressure and temperature changes computed from ECLIPSE results in the deformation of cells in VISAGE, which has an effect on pore volumes, pressure and temperatures that are in turn used in ECLIPSE. This coupling methodology, while it is two-way, is referred to as “loose coupling.” This also allowed us to run quite a number of timesteps in ECLIPSE for each step in VISAGE as the fluid flow occurs a lot faster than the geomechanical deformation.

At a given coupled time step, the rock stress state will determine the aperture. Then the effective permeability can be computed using the updated aperture results from VISAGE. This process is summarized in the flow chart in Figure 1. The effective permeability is computed for each grid using the local cubic law (Oron and Berkowitz 1998) and is expressed as

$$k_{f_i} = \frac{b^2}{12} \quad (1)$$

where k_f , i , b , are the effective permeability, grid number, and local fracture aperture respectively.

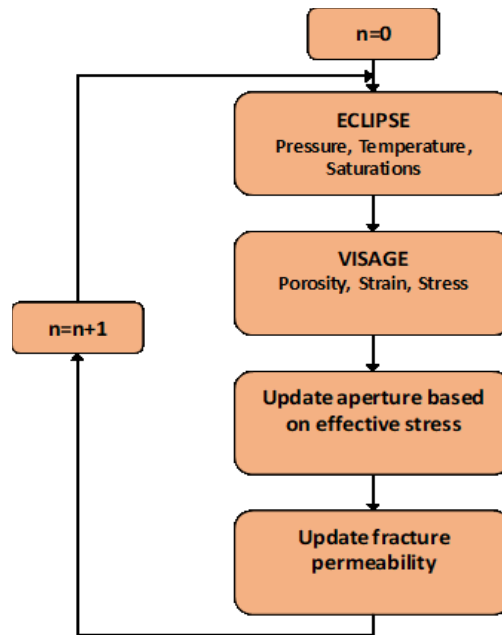


Figure 1: Procedure for two-way Thermo-Hydro-Mechanical Coupling between ECLIPSE and VISAGE where n is the coupling time step.

2.2 Solution Verification

Prior to modeling the Enhanced Geothermal System, the Thermo-Hydro-Mechanical coupling was evaluated for a plane fracture geometry as seen in the work by Ghassemi, Nygren and Cheng, 2008. They solved the problem analytically for cases with a constant fluid injection rate with a constant leak-off rate. The numerical model in this study was used to solve the problem of constant fluid injection rate but the leak-off rate was set as zero. The comparison between the analytical model and the numerical model is shown in Figure 2. The normalized induced aperture represents the ratio of the aperture at the injection point at the specified time to the aperture at the injection point at the initial time. Once it was established that the coupled numerical model could solve the EGS-type geomechanical problem correctly, the procedure was applied on the three-dimensional system describing the EGS to be modeled.

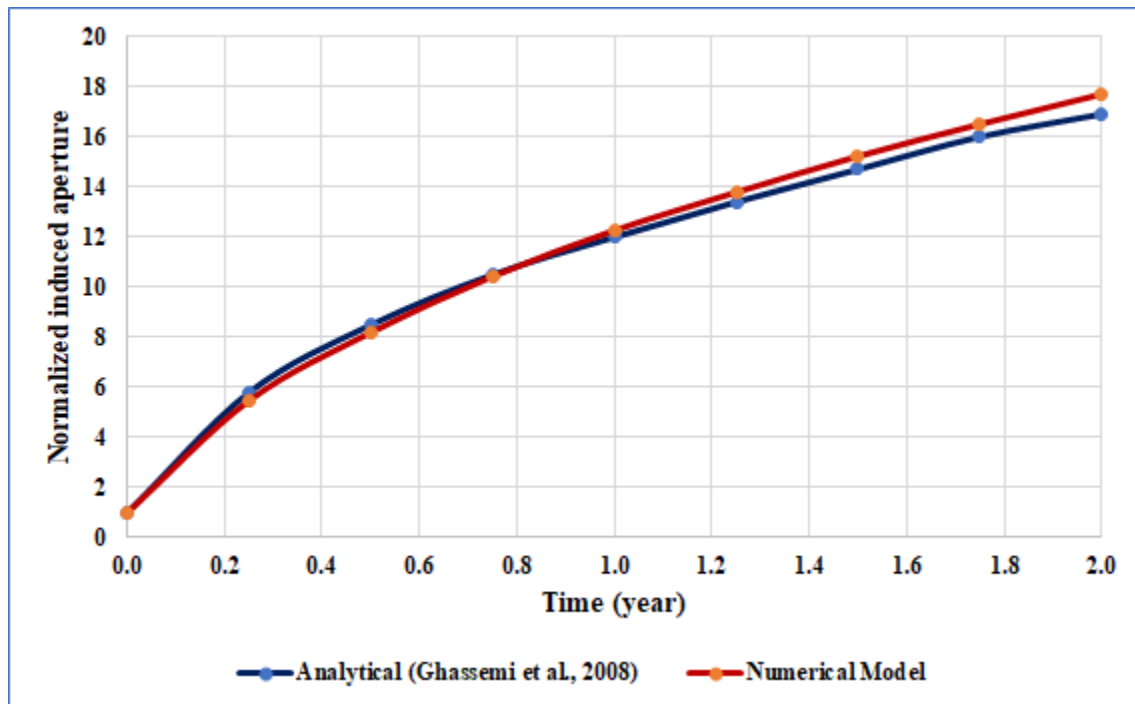


Figure 2: Comparison between the Analytical and Numerical Model results for Normalized Thermoelastic-Induced Fracture Aperture at the Injection Point.

2.3 Model Description

The thermo-hydraulic model is a three-dimensional simulator consisting of a single horizontal fracture measuring 1000 m x 1000 m and is embedded within the relatively impermeable bulk rock matrix. The target fracture is situated at a depth of 3095.5 m below ground surface. Horizontal wells, one injection and one production, are placed at the edges of the fracture. Two injection-production well configurations are possible relative to the fracture shear offset. When the fluid flow and pressure drop are applied parallel to the lateral direction of shear offset, this configuration is referred to as the “parallel flow configuration.” In the perpendicular flow configuration, flow and pressure drop are perpendicular to the lateral direction of shear offset. The flow configurations are illustrated in Figure 3.

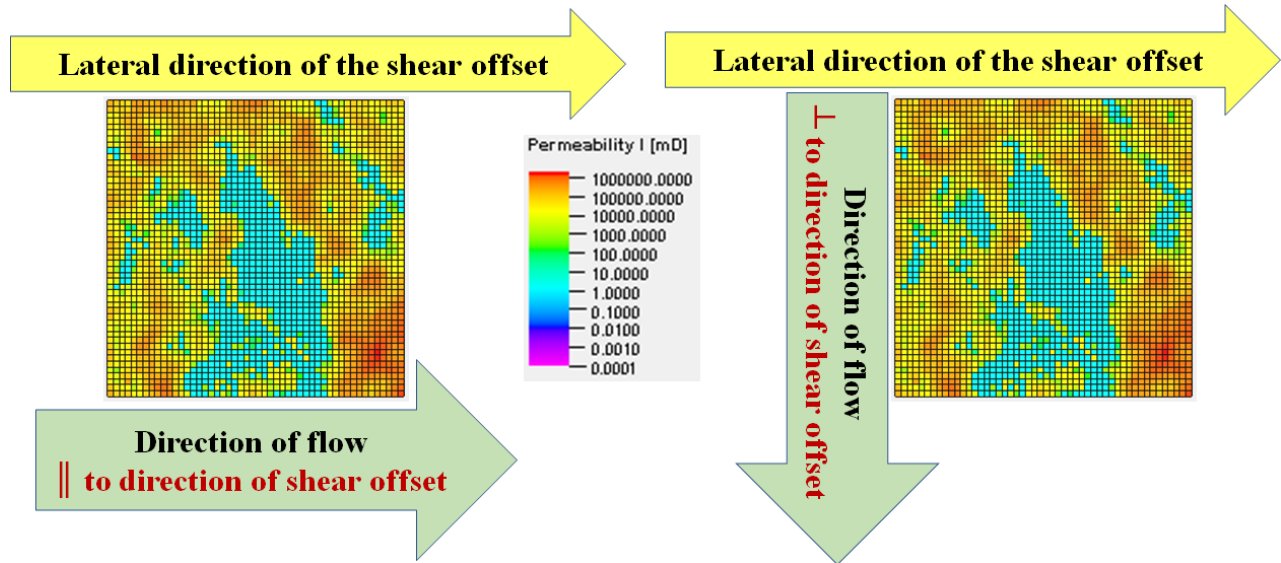


Figure 3: Flow configurations with respect to the lateral direction of shear offset. Permeability is the displayed property on the fracture's x-y plane. On the left is parallel flow configuration while on the right is perpendicular flow configuration.

A nonuniform aperture field was collected from the work by Ishibashi, et al. (2012). From their work, the fracture aperture map of the 5 cm × 7.5 cm sheared fracture was upscaled assuming the aperture distribution to be self-similar, and a square section of it was used to describe the fracture of the model in this study. The apertures were also made to have a maximum value of 7 mm to ensure the simulations were not too different from the case of a fracture with constant aperture of 7 mm. This is shown in Figure 4. The fracture permeability was computed using the local cubic law and the permeability became an input for the three-dimensional model characterizing the layer represented by the fracture. Fluid flow is predominantly within the fracture as the formation permeability is relatively small. Leak-off from the fracture into the formation is assumed to be negligible. The fluid flow is maintained at 20 l/s and the initial pore pressure is set at 130 bar with an initial reservoir temperature of 200 °C at the target fracture depth.

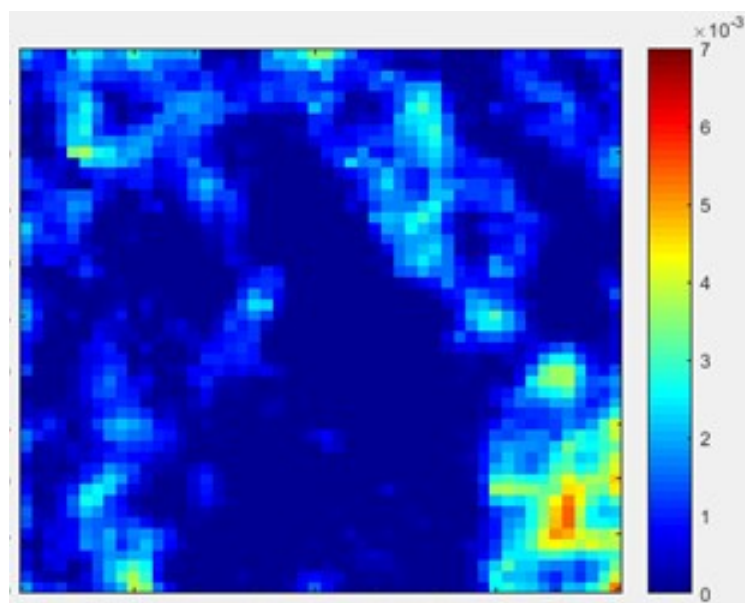


Figure 4: Aperture distribution used to characterize the fracture plane. The height of the apertures are in units of meters.

The thermo-hydraulic model is embedded within the geomechanical simulation domain. The geomechanical model has geometrically gridded cells beyond the hydraulic reservoir model. The geomechanical model also extends to a much further boundary, to simulate the tectonic boundary condition being applied in the far-field. The dimensions of the coupled simulation domain are approximately $3 \text{ km} \times 3 \text{ km} \times 3 \text{ km}$. This is shown in Figure 5. The geomechanical model takes the rock and fluid properties of the thermo-hydraulic model where applicable.

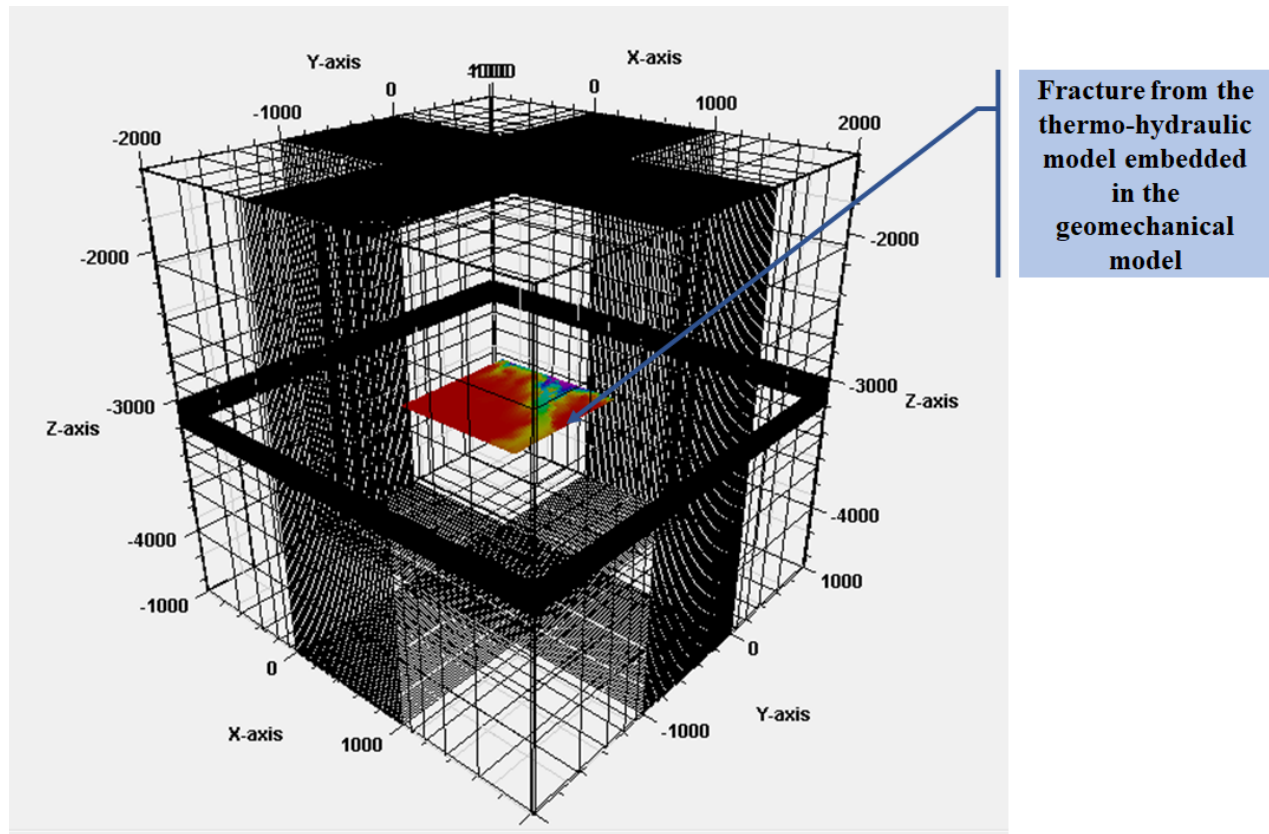


Figure 5: Fracture from the thermo-hydraulic (TH) model embedded within the geomechanical model. The dark color shows the degree of refinement of the model. For the geomechanical model, the grids become coarser away from the TH model.

The principal stresses imposed on the model include 350 bar for the vertical stress, 500 bar for the minimum horizontal stress, and 700 bar for the maximum horizontal stress. The maximum water injection pressure is 220 bar and throughout the simulation the fluid pressure remains below the minimum principal stress. Additional rock and fluid properties used in the simulations are presented in Table 1. The dependence of water viscosity, specific heat capacity of water and the water compressibility on temperature and/or pressure were considered in the simulation.

Table 1: Rock and fluid properties, and other parameters used in the model

Property	Value	Unit
Porosity of the formation matrix	0.01	-
Permeability of the formation matrix	0.00001	mD
Rock solid density	2820	kg/m ³
Thermal conductivity of rock matrix	2.4	W/m/K
Specific heat capacity of rock	1600	J/kg/K
Linear thermal expansion coefficient of rock matrix	8.00E-06	1/K
Rock Young's Modulus	66	GPa
Poisson's Ratio	0.185	-
Rock shear modulus	27.5	GPa
Water density	1000	kg/m ³
Volumetric thermal expansion coefficient of water	7.50E-04	1/K

3. RESULTS AND DISCUSSION

Presented and discussed below are the results for the two different flow configurations for five years of continuous fluid circulation. The time steps presented are 3 months, 1 year and 5 years of circulation. The figures show the spatial distributions of fracture aperture and fluid flow paths based on the THM model and compare the temperature distribution of the TH model with the THM model. Note that though fluid flow is three-dimensional, the flow rate for the perpendicular scenario is predominantly in the y-direction while the flow rate for the parallel flow configuration is predominantly in the x-direction hence only the flowrates in the predominant directions are presented.

The first set of results are for the case where the water viscosity is temperature dependent. The second set of results are for the case where the water viscosity is constant. A value of 0.15 cp was used in the constant water viscosity case to represent the average viscosity of water within the simulation temperature range.

3.1 Perpendicular Flow Configuration with Temperature-Dependent Water Viscosity

Figure 6 shows the spatial distribution of aperture, fluid flow path and temperature at the fracture during sustained cold-water circulation for the perpendicular flow configuration. Temperatures within the bulk-rock cool as a result of cold-water injection and this results in the accumulation of thermally-induced tensile stresses. The creation of tensile thermal stress reduces the compressive total vertical stress causing a redistribution of vertical stress within the rock. This causes displacement of the rock around the fracture, which is translated to changes in the aperture.

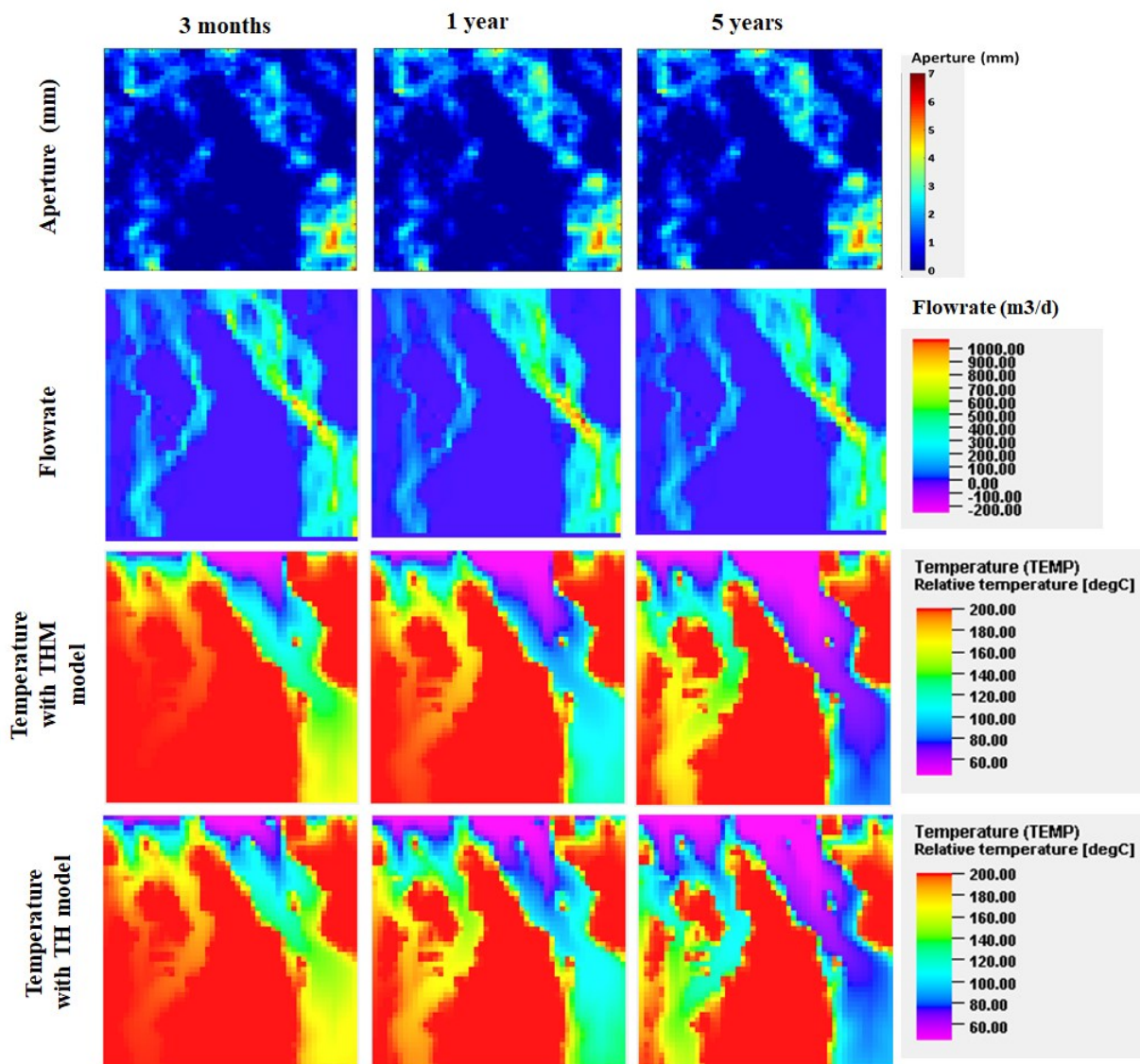


Figure 6: Evolution of fracture aperture distribution, fluid flow paths, and the temperature distribution for the perpendicular flow configuration. The “THM model” includes the thermoelastic effects of thermal stresses while the “TH model” does not.

The evolution of aperture distribution, the flow rate, the temperature distribution based on the THM model and the temperature distribution based on the TH model are shown at 3 months, 1 year and 5 years. From the aperture map, the impact of the thermal stress is two-fold: first it causes an increase in the aperture in the direction of higher flowrate and secondly it causes a reduction in the flowrate outside the preferential flow path. This intensifies flow channeling and as time progresses, less area is available for contact with the injected fluid. The flow becomes concentrated within the preferential path resulting in this region in contact with the fluid cooling faster than if the thermal stresses did not impact the aperture. Thus, by the fifth year, the larger channel within the fracture aperture shows faster cooling when compared to the case of the TH model.

3.2 Parallel Flow Configuration with Temperature-Dependent Water Viscosity

A similar analysis to that done for the perpendicular flow configuration was done also for the parallel flow configuration. Figure 7 shows the evolution of aperture distribution, the flow path, the temperature distribution based on the THM model and the temperature distribution based on the TH model for the parallel flow configuration. From the aperture maps, there is some increase in aperture along the direction of the preferential flow path. The flow path map shows that flow is concentrated within the preferential path with time resulting in flow channeling. This is intensified with time and less area is contacted by the circulating fluid.

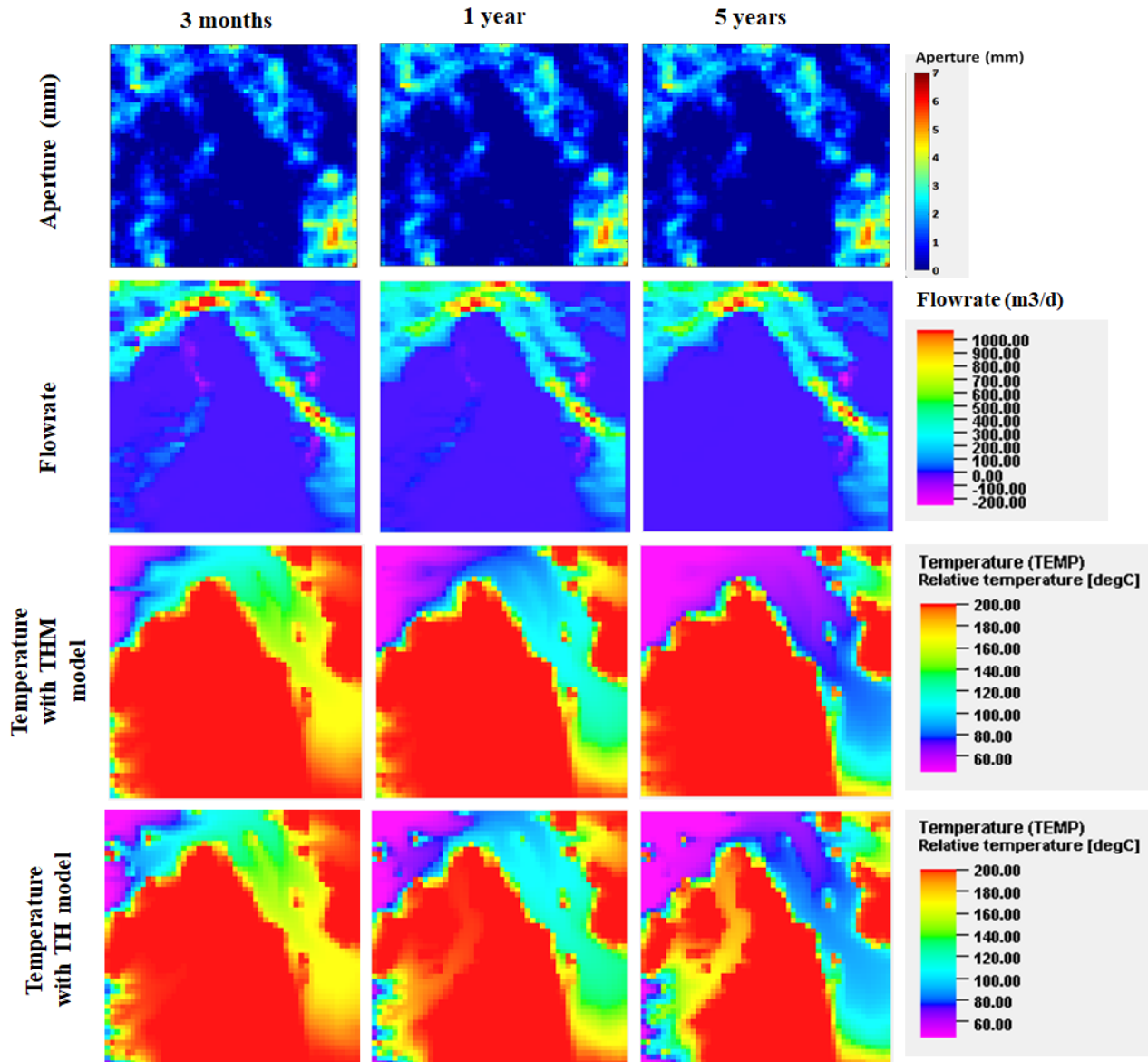


Figure 7: Evolution of fracture aperture distribution, fluid flow paths, and the temperature distribution for the parallel flow configuration.

3.3 Comparison of the Thermal Performance of the Different Flow Configurations: Temperature-Dependent Viscosity

The presence of thermal stress and the consequent exacerbation of flow channeling is seen to affect the thermal performance of the system in both flow configurations. Figure 8 is a plot of the temperature at the producer as a function of time. The temperature at the producer based on the TH model is compared with the temperature of the producer based on the THM model for both flow configurations.

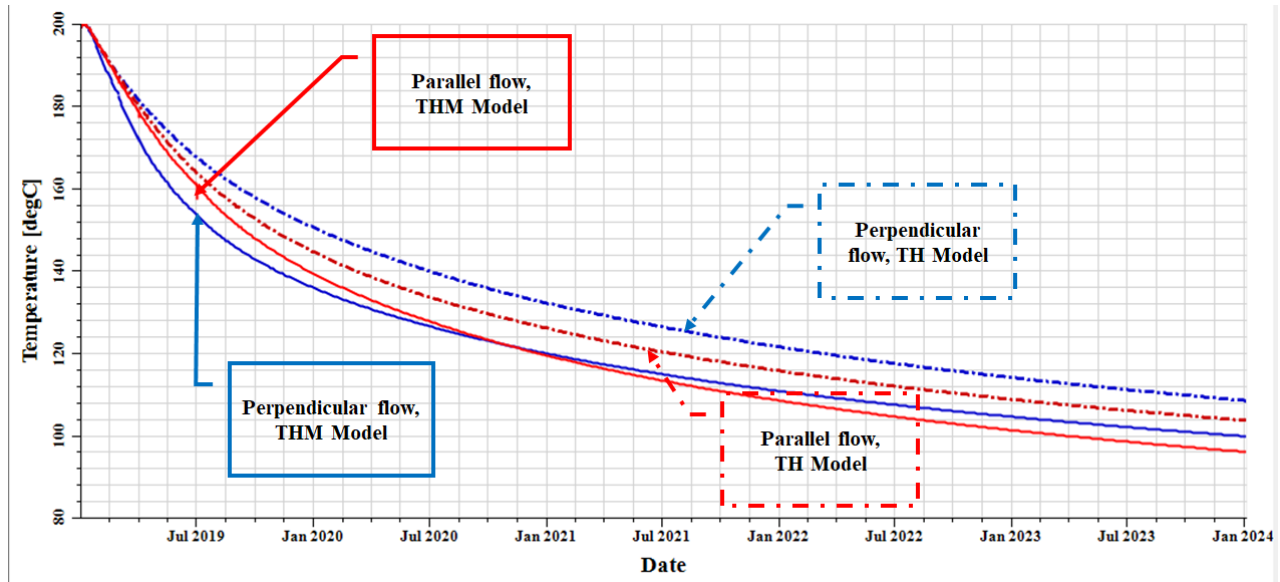


Figure 8: Production well fluid temperature for the thermo-hydro-mechanical (THM) model and the thermo-hydraulic (TH) model for the perpendicular and parallel flow configurations.

In general, the temperature profiles from the thermo-hydraulic-mechanical models show a poorer thermal performance at any given time compared to the thermo-hydraulic model. This shows that thermal stresses have some impact on the behavior of fluid circulation within fractures of heterogeneous aperture distributions. In the first two years, it seemed the parallel flow configuration had a better thermal performance but beyond two years, cooling within the preferential path was exacerbated (Figure 7). The role of temperature-dependent viscosity comes into effect here in that as temperature drops, the fluid becomes more viscous and would tend to follow less restrictive paths if available. For the perpendicular flow configuration, at later times, cooling is seen to take place in alternative paths (Figure 6) based on the spatial temperature distribution at the fracture. This is not the case for the parallel flow configuration (Figure 7) when comparing the spatial temperature distribution of the thermo-hydraulic-mechanical model with the thermo-hydraulic model.

3.4 Perpendicular Flow Configuration with Constant Water Viscosity

Figure 9 is a comparison between temperatures at the fracture with and without thermoelastic considerations. The results are based on sustained cold-water circulation for the perpendicular flow configuration assuming constant water viscosity. Similar to what was observed in the case of temperature-dependent viscosity, the temperatures within the bulk-rock cool as a result of cold-water injection and this results in thermally-induced tensile stresses. Also intensified flow channeling is observed in the THM model but by the fifth year, the difference between the results of the THM model and the TH model are not significant, suggesting that assuming constant water viscosity may not appropriately account for the effects of thermally-induced stresses and channeling.

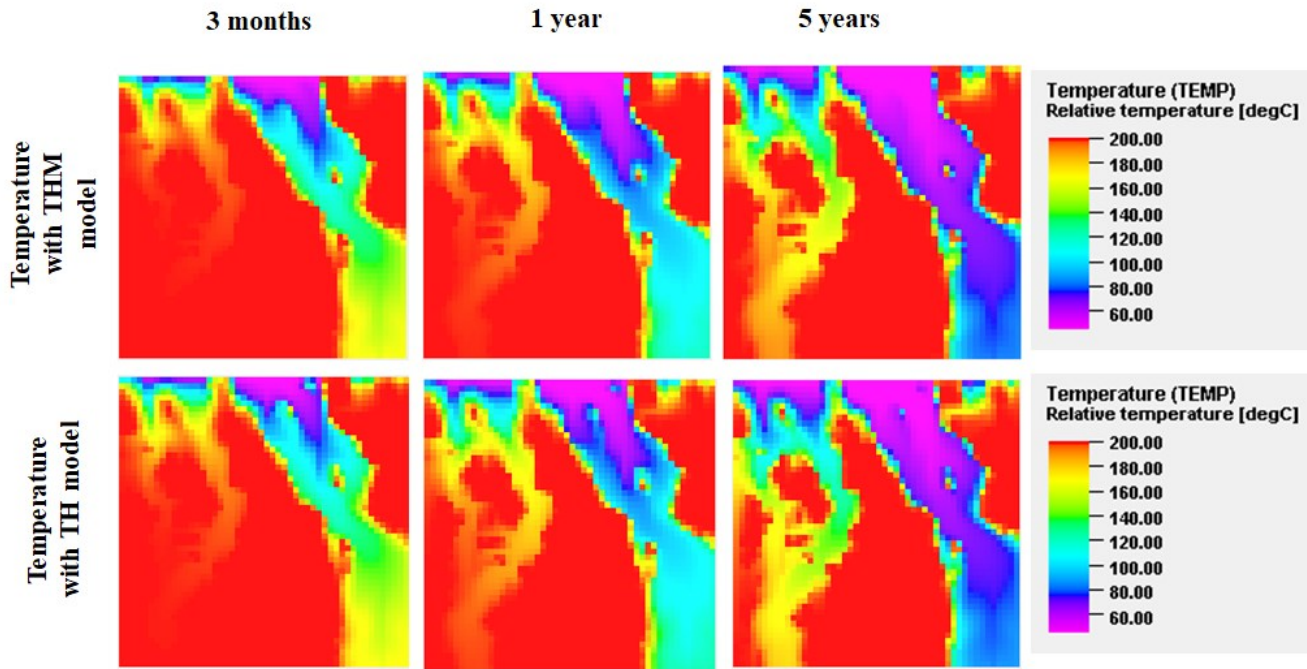


Figure 9: Comparison of the temperature distribution for the perpendicular flow configuration assuming constant viscosity. The “THM model” includes the thermoelastic effects of thermal stresses while the “TH model” does not.

3.5 Parallel Flow Configuration with Constant Water Viscosity

Figure 10 shows the temperature distribution based on the THM model and the temperature distribution based on the TH model for the parallel flow configuration. While there is evidence of flow channeling, there is not much difference between the THM model and the TH model for the five-year duration of sustained fluid circulation. This is also seen in Figure 11 which shows the temperature profile at the producer for the different flow configurations.

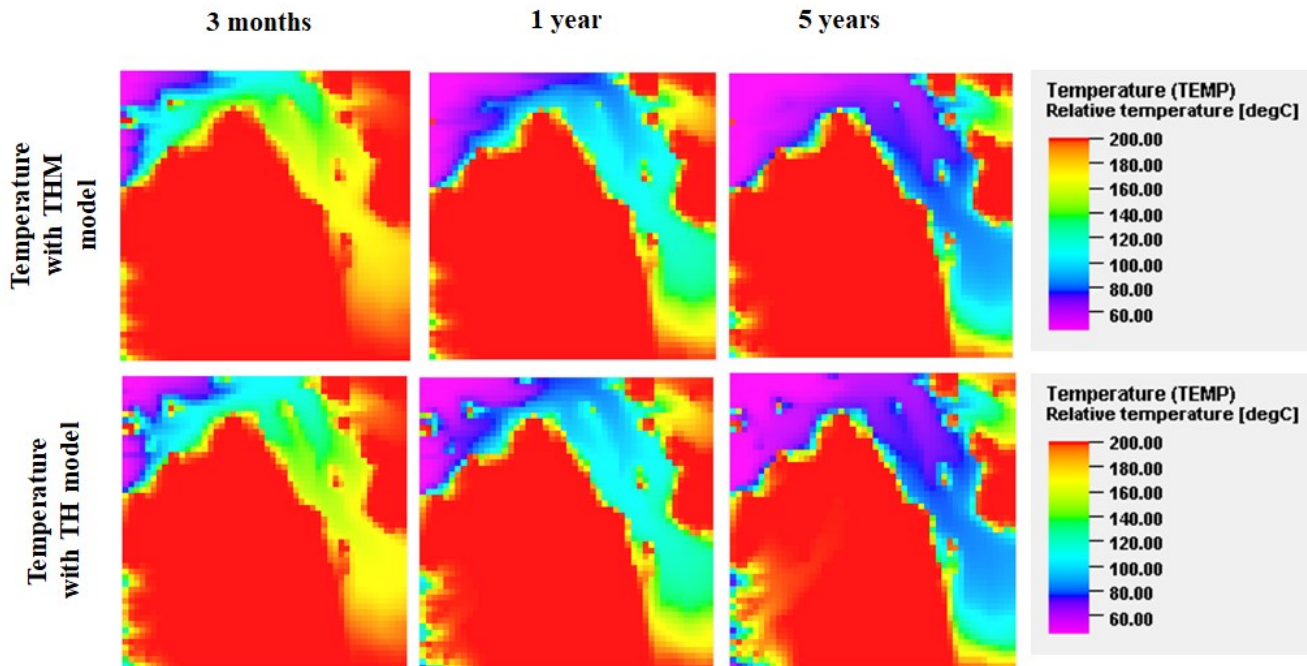


Figure 10: Evolution of the temperature distribution for the parallel flow configuration – assuming constant water viscosity.

3.6 Comparison of the Thermal Performance of the Different Flow Configurations: Constant Water Viscosity

Figure 11 is a plot of the temperature at the producer as a function of time. The temperature at the producer based on the TH model is compared with the temperature of the producer based on the THM model for both flow configurations.

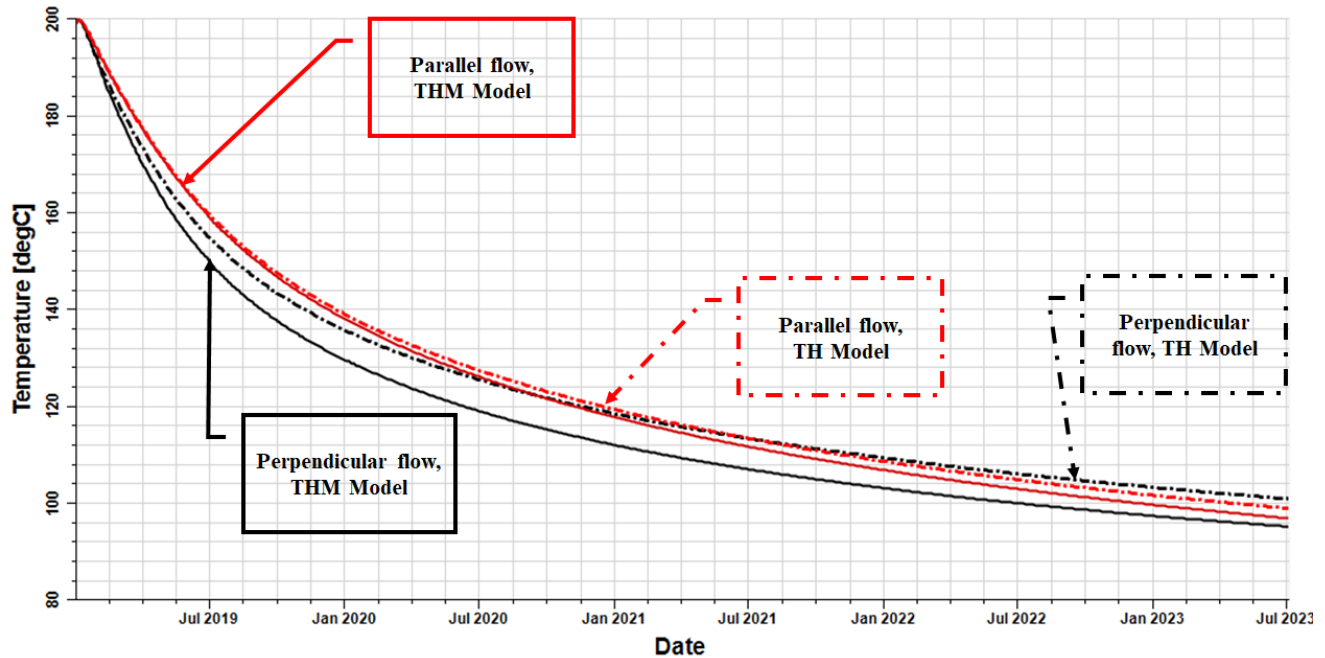


Figure 11: Production well fluid temperature for the thermo-hydro-mechanical (THM) model and the thermo-hydraulic (TH) model for the perpendicular and parallel flow configurations. Water viscosity remained constant in both models.

In general, the temperature profiles from the thermo-hydraulic-mechanical models show a poorer thermal performance at any given time compared to the thermo-hydraulic model. This shows that thermal stresses have some impact on the behavior of fluid circulation within fractures of heterogeneous aperture distributions. A few differences are seen in Figure 11 when comparing with the case of temperature-dependent water viscosity (Figure 8). First the parallel flow configuration appears to give a better thermal performance than the perpendicular flow configuration in both the TH and THM models until about 2.5 years later where the perpendicular flow configuration of the TH model seems to show a slightly improved thermal performance over the parallel flow configuration. Secondly, for the parallel flow configuration there is not much difference between the thermal performance of the TH model and the THM model. A plausible reason for these differences might be the choice of the constant viscosity used, that is, perhaps a higher viscosity may give results similar to what was seen in the case using temperature-dependent viscosity. Also perhaps a different aperture distribution may result in somewhat different results. These are yet to be investigated.

4. CONCLUSIONS

The injection of cold fluid for the purpose of heat extraction in Enhanced Geothermal Systems can lead to the creation of thermal stresses within the rock body. Where the fracture is characterized by spatial variations, the presence of thermal stress can lead to exacerbation of flow channeling, a phenomenon known to occur when fluid flows through preferential paths due to the spatial variations of aperture in sheared fractures.

A numerical approach was used to investigate the impact of thermal stresses on EGS performance. From this study, it has been shown that accounting for the thermal stresses could predict EGS thermal performance and the results would differ from a case where thermal stresses are not accounted for. The intensified flow channeling as time progresses has been shown to cause impaired thermal performance. This could lead to earlier thermal breakthrough.

From the results of the temperature-dependent water viscosity, based on the temperature histories of the thermo-hydraulic-mechanical model, the long-term thermal performance of the perpendicular flow configuration for the given aperture distribution appeared to be better than the performance of the parallel flow configuration, although this was not the case in the first two years. This may suggest preferred well configurations relative to shear offset as well as possible better times to exploit the thermal resource.

For the results using constant water viscosity in the models, the difference between the results of the THM model and the TH model are not significant, suggesting that assuming constant water viscosity may not appropriately account for the effects of thermally-induced stresses and channeling.

Further studies will evaluate thermal stresses in systems with other aperture distributions, other values of constant viscosity, as well as investigate the behavior with real data.

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