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A 3D numerical geothermal reservoir model has been developed for the purpose of studying coupled changes in reservoir permeability, heat transfer and fluid flow due to long term production and thermal drawdown (Koh et al., 2011). This study integrates four key elements: a natural fracture characterization model, a fluid flow simulation model, a heat transfer model and a geomechanical stimulation model. Fluid flow is simulated by fully coupling stresses and temperature to the flow equations. The heat transfer model is based on conductive heat transfer within the reservoir rock, convective heat transfer through the reservoir fluid and time dependent thermal equilibrium between the rock and fluid. The stimulation model simulates the shearing of fractures and the stress dependent permeability changes in a dynamic process by coupling the thermo-poroelastic fluid flow and the shear dilation analysis.

Patchwarra geothermal reservoir was used as a field case to study the degree of stimulation that can be achieved and subsequent thermal drawdown over a productive life. A stochastic fracture network (Tran and Chen, 2007) of the Patchwarra field was generated based on the data available in the open literature (Mildren et al. 2007). The reservoir was subjected to different pressure cycles to determine the degree of permeability enhancement that could be achieved. Stress changes due to thermal drawdown and consequent change in permeability over the reservoir's productive life was monitored. Flow rates and corresponding pressure losses between the injector and producers as well as heat recovery of the produced water were calculated to assess the geothermal potential of the reservoir. Different well placement scenarios were examined to assess the impact of directional fracture interconnectivity on production rates. The results of this study has shown that directional fracture interconnectivity and injection schedule has a profound effect on heat recovery from enhanced geothermal systems. This has allowed us to select an optimum well placement scenario which maximises the production rate with minimum pressure loss.

We have also observed that effective tensile normal stresses induced by the injected cold fluid tends to increase fracture apertures, and hence, increase fracture permeability within the zone of cooling (Ghassemi and Kumar, 2007).

Keywords: Geothermal, EGS, stimulation, thermal drawdown

Results and Discussion

Results of shear dilation are presented as average percentage increase in fracture aperture and dilation events with time. From Fig. 1, it can be seen that there exists three distinct periods: 0-28 weeks, 28-42 weeks and greater than 42 weeks. Until about 28 weeks, the rate of occurrence of dilation events due to induced fluid pressure remains fairly constant. Following this time, the rate of occurrence of shear dilation increases sharply until about 42 weeks. This phenomenon can be explained as follows. Due to the anisotropic stress state of the reservoir rock, there exists resultant shear and normal traction components along variably oriented fracture planes. When the reservoir pressure increases (due to stimulation pressure), the normal traction components (compressive initially) on the fracture planes diminish, however, the shear components prevail. Eventually, the fracture shear dilation pressure is reached, whereby the normal (compressive) traction on the fracture plane is insufficient in preventing shear failure and the fracture undergoes slip in shear and dilates. This results in a large fold increase in permeability and allows rapid propagation of fluid pressure through the fracture network. Eventually, reservoir permeability increases significantly, both due to

![Figure 1: Average increase in fracture apertures due to stimulation](image-url)
pressure induced inflation (temporary) and shear dilation (retainable) of the fracture network. At this time, as seen through the 2nd inflexion point in Fig. 1, most fractures have been jacked open and all the shear tractions on the fracture planes have been mobilized for shear dilation. Thereafter, no significant dilation events can be observed (a plateau of events is reached).

Pore Pressure and Fluid Velocity Distribution

The fluid pore pressure distribution and the RMS fluid velocity profile in the reservoir after 5 years are presented in Figs. 2 and 3 respectively. In Fig. 2, the pressure profile between injector and producer is reasonably smooth as the pore pressure has had time to establish a quasi-steady state. The velocity profile shown in Fig. 3 illustrates the ability of the model to retain a high level of heterogeneity and regions of high and low velocities are clearly seen distributed throughout the flow domain. The fluid velocities distributed through the fracture network become concentrated close to the injection and production wells.

Figure 2: Reservoir pore pressure profile after 5 years of production with 1000 psi pressure loss between injector and producer.

Figure 3: Rms fluid velocity profile after 5 years of production with 1000 psi pressure loss between injector and producer.

Rock and Fluid Temperature Distribution

In Figs. 4 and 5, the changes in rock temperature over a period of 5 and 20 years respectively are presented. It can be seen from these figures that at early time, the temperature of the rock body remains quite high. During late time (20 years), the rock body cools down and the direction of cooling is influenced by the fracture orientations.

Figure 4: Reservoir temperature profile after 5 years of production with 1000 psi pressure loss between injector and producer.

Figure 5: Reservoir temperature profile after 20 years of production with 1000 psi pressure loss between injector and producer.
Effect of Increased Production Rate

It is observed that with increase in production rate, the rock body cools at an increasing rate, which in turn results in faster thermal breakthrough of the production fluid (see Fig. 6). Net effect of rapid thermal breakthrough as such is derived from the fact that the residence time of fluid within the fracture network is insufficient to capture sufficient heat from the hot rock matrix.

Effect of Thermal Stresses

The effective stresses in the reservoir rock at early production time (3 years) and late production time (10 years) are presented in Fig. 7 (x direction). It should be noted that a geometronics sign convention is adopted for stresses (positive for compression). From both plots, it is apparent that the effective stresses in reservoir at late time (10 years) are significantly less compressive than those at early time. The decreases in effective stresses causes fracture dilation and therefore permeability enhancement.

Conclusions

In this paper, a thermo-poroelastic reservoir model is developed and used to study the effect fluid induced pressure on the stimulation of naturally fractured geothermal reservoirs. The Patchwarra Formation in the Cooper Basin, Central Australia was used in the numerical study.

The effect of varying the production rate for a given pressure drop between the injector and producer was assessed. The net effect of increased flow rate is correlated with a more rapid thermal breakthrough and production fluid cooling. This can be attributed to the thermo-hydro-mechanical coupling in the simulation model.

The circulation of cold water induces tensile thermal stresses which allow residing fractures to dilate and enhance permeability.

References

Ghassemi, A. and G. Suresh Kumar (2007). “Changes in fracture aperture and fluid pressure due to thermal stress and silica dissolution/precipitation induced by heat extraction from subsurface rocks.” Geothermics 36(2): 115-140.


