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Impact of Fracturing Caused By Cold Water Reinjection in Geothermal Reservoir On Early Cold Water Breakthrough In Production Wells

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ABSTRACT

Cold water injection into a reservoir, can cause reservoir rock fracturing, which in turn, can induce early cold water breakthrough into a production well. The objective of this work is to investigate hydraulic fracture propagation in liquid-dominated geothermal reservoir and to establish how it effects cold water breakthrough in production wells. For this purpose, a 2D reservoir simulator describing fully-coupled interaction among fluid flow, thermal flow, geomechanical reservoir behavior and fracture growth was used in this study.

The paper explains how to estimate fracturing pressure change due to cold water injection. It also discusses how to predict orientation/re-orientation of hydraulic fracture propagating from an injector.

1. INTRODUCTION

The mechanical behavior of a body, i.e. the changes in its dimensions (its deformation), or in some cases its failure, depends on the external and internal forces distribution acting on the body. Considering an infinitesimal cube isolated from the body, it is held in equilibrium by forces imposed on its surfaces. The cube can be oriented in such a way that only forces normal to its surfaces are present. Under these conditions there are three pairs of independent forces since the cube is in equilibrium.

The physics of the geomechanical behavior of a geothermal reservoir, and its mathematical description, are rather complex due to the porous nature of the rock coupled with fluid flow (multiphase flow) through the pores.

The strain concept is used to describe deformation of a material and it is directly related to displacement through strain/displacement relations. When modeling deformation of a poro-elastic medium we use the continuum mechanics (continuous medium) concept. One of the main ideas of the theory is that the stress in a saturated porous material is 'carried' partially by the pore fluid and partially by the solid matrix. This is the so-called total stress and it refers to the bulk volume of the rock. The part of the total stress carried by the solid rock matrix, is called effective stress, and it represents the actual state of stress in the solid rock grains.

Fluid injection into a reservoir, and production from the formation, perturbs the local in-situ stress state. The stress can either be altered by changes in pore pressure, or by temperature perturbations in non-isothermal flow.

Sufficiently accurate estimation of reservoir stresses becomes essential in many geothermal injection – production operations when a reservoir is brought closer to fracturing conditions. This is because induced stress changes may cause formation fracturing. The fracturing may cause early cold water breakthrough into production wells. In naturally fractured/stress sensitive reservoirs the state of stress changes cause opening or closing of existing fractures and permeability variations.

2. FORMULATION OF THE COUPLED MODEL

A fully coupled fluid flow, thermal flow, and geomechanical behavior model incorporates the fluid flow equation with energy conservation and stress equilibrium equations. Energy balance law was assumed under the following assumptions (Rewis, 1999):

- the only energy transfer to the system is by convective and conductive heat transfer through the boundary, and mechanical work done by surface traction

- kinetic energy changes are small compared to those of the internal energy

- negligible viscous dissipation

- instantaneous local thermal equilibrium between rock and fluid.

To determine stress variations in the system, the following governing equations from the theory of poro-thermo-elasticity are used. Computer code is used to solve the following system of equations (Chen et al., 1995):

$$G\cdot\nabla^2 u_i+(G+L)\cdot\frac{\partial}{\partial i}(\nabla\cdot\mathbf{u})+\alpha_B\cdot\frac{\partial P}{\partial i}+(2\cdot G+L)\cdot\frac{\partial(\alpha_T\cdot T)}{\partial i}=0 \qquad i=x,y \tag{1}$$

$$\nabla\cdot\left(\frac{k}{\mu_f}\cdot\nabla P\right)=c_t\cdot\frac{\partial P}{\partial t}-\beta_t\cdot\frac{\partial T}{\partial t}-\alpha_B\cdot\frac{\partial}{\partial t}(\nabla\cdot\mathbf{u}) \tag{2}$$

$$\nabla\cdot(\lambda\cdot\nabla T)-\nabla\cdot\left(\frac{\rho_f\cdot k\cdot C_f\cdot T}{\mu_f}\cdot\left(\nabla P+\frac{P}{\rho_f}\right)\right)=\frac{\partial}{\partial t}\left((1-\phi)\cdot\rho_s\cdot C_s\cdot T+\phi\cdot\rho_f\cdot C_f\cdot T\right) \tag{3}$$

where:

u – displacement vector, m,

G – shear modulus, Pa,

L – Lame's constant, Pa,

α_B – Biot's poroelastic coefficient, -,

P – pressure, Pa,

α_T – coefficient of thermal linear expansion, 1/K,

T – temperature, K,

k – permeability, m2, mD

μ_f – viscosity of fluid, Pas,

c_t – total isothermal compressibility of reservoir, 1/Pa,

β_t – total isobaric compressibility of reservoir, 1/K,

t – time, s,

λ - thermal conductivity, W/mK,

C_f, C_s – heat capacity of fluid and solid, J/kgK

ρ_f, ρ_s – density of fluid and solid, kg/m3,

ϕ - porosity, -.

Geomechanical behavior of a rock - its deformation/failure - in general is very complex, and primarily depends on the particular type of a rock, and stress state to which the rock is subjected. It is a common practice to consider different "modes of rock behavior"/"modes of failure" when mathematically describing the process. So far, we focused our attention on elastic mode of deformation of rock skeleton in which linear relation between stress and strain holds. In the mode of behavior the process is believed to be reversible, i.e., rock would return to the original form/shape once the state of stress returns to the original value.

Perhaps the most evident impact of reservoir stresses on its performance may be observed when rock undergoes a failure (fracturing), changing dramatically its structure, which in turn may drastically affect rock permeability. Formation rock fracturing occurs after the state of stress reaches a critical value. Again, depending on the rock type/its behavior, and particular stress state, the rock may fail in a certain mode, such as:

- tensile fracturing

- shear fracturing

- yield of plastic deformation

The tensile mode of failure is of particular interest when considering water injection induced hydraulic fracturing. When water is injected into a reservoir, the compressive effective stress acting on the rock matrix decreases, due to pore pressure increase. Eventually it may reach a critical value at which the rock will be fractured along a plane perpendicular to the minimum principal stress. The pore pressure at which fracture will be initiated is called fracture initiation pressure or fracturing pressure.

Both physical processes, water injection and conventional hydraulic fracturing involve injection of fluid into the porous rock at the pressure which allows for creating tensile fracture in the rock matrix. However, injection of low viscosity fluid, such as water, differs drastically from traditionally encountered during hydraulic fracturing high viscosity completion fluids, due to higher leak-off rates during water injection. In addition, time scale of conventional hydraulic fracturing is on the order of day, while water injection fractures may grow through reservoir for periods of months or years.

As a consequence, the modeling of both phenomena differs significantly. The following factors normally not included in conventional hydraulic fracturing modeling, may become important when considering water injection fractures (Settari and Warren, 1994):

- Significant pressure and saturation gradients may exist around the well due to production/injection from/into the reservoir. Therefore, it cannot be assumed that the fracture will propagate through a reservoir with constant properties.

- Different leak-off rate along the fracture caused by large scale reservoir heterogeneity (variations in permeability, porosity)

- Well interference may affect fracture propagation

- Long term cold water injection can create cooled zone around the fracture and alter state of stress as well as fluid properties

- Average reservoir pressure and stress can change during the time of fracture growth

- Simple analytical leak-off models cannot easily approximate large leak-off zone around the fracture with three-dimensional saturation and temperature distribution.

2.1 Mathematical Description and Mechanism of Water Injection Induced Fracture

The following assumptions are made in the mathematical representation of water injection fracture:

A vertical fracture is created and propagates from a vertical wellbore coinciding with the major principal stress axis. The fracture has rectangular surface, its height is constant and equal to the thickness of the reservoir (see Figure 1).

Pressure drop along the fracture can be neglected due to its infinite conductivity

The injection rate from the well into the fracture equals the total flow rate from the fracture (leak-off) into the reservoir. The rate of fracture volume change is negligible with respect to the total leak-off rate.

The analysis is restricted to two-dimensional domain, in the xy plane (see Figure 1), so that a simple linear fracture is embedded in a linearly elastic rock layer deforming under plane-strain conditions.

In the so called water injection fracture model, developed under the above assumptions, basic parameters which describe its physical behavior are: fracture dimension factor (its half-length, L_f), fracture initiation pressure (P_{fi}), fracture pressure (P_f), fracture opening/closure pressure (P_{foc}) and fracture propagation pressure (P_{fp}).

Pressure inside the fracture at the current time is always bounded by the two values of fracture opening/closure pressure, and fracture propagating pressure, i.e.:

$$P_{foc} \le P_f \le P_{fp} \qquad (4)$$

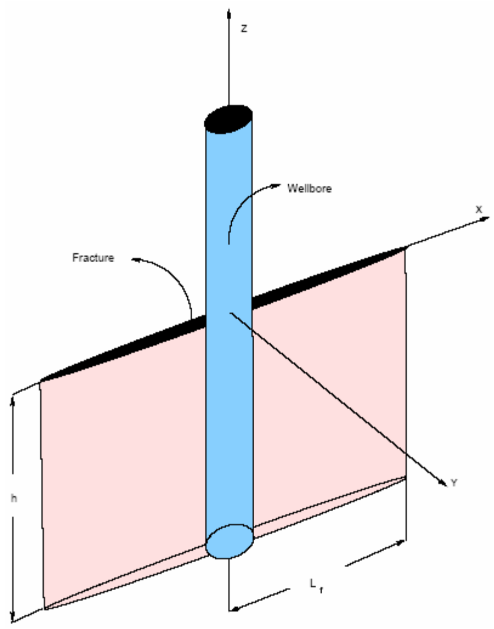

Figure 1: Fracture Geometry.

Once the fracture is initiated, it will grow/propagate further and further through the reservoir, then eventually its length may be stabilized or it will start closing. Its status (length) at the current time, depends on the pressure inside the fracture, state of stress imposed on fracture wall, and its mechanical parameter (fracture toughness). For the given length of the fracture, minimum pressure is required to prevent its closure.

The propagation of the fracture is modeled using the concept of a critical stress intensity factor K_{IC}, which is based on the balance of strain energy and free surface energy for a static fracture (Thiercelin, M.J. and Lemanczyk, Z.R, 1983).

Numerical simulator solve system of P.D.E. given above with fracture model in two-dimensional domain, under plain strain assumption using control-volume finite difference discretization (Rewis A., 1999; Osorio J.G. et al. 1999).

3. THERMAL STRESS AND FRACTURE PROPAGATION DURING INJECTION INTO GEOTHERMAL RESERVOIR

The response of a reservoir volume was analyzed to investigate the effects of temperature changes on stress perturbations during cold water injection. The plane strain condition is assumed and single-phase, slightly compressible fluid flow. No fluid or heat flow in the vertical direction is allowed. Following these assumptions pore pressure, temperature, displacement, and the stress field will not change in the vertical direction and the problem can be solved in 2D. Furthermore, the grid boundaries coincide with the directions of the initial principal horizontal stresses. Constant injection rate is specified at the well. Because of symmetry a quarter of the area is considered and no flow boundary conditions along left and bottom boundary. Constant pressures along right and top boundary are assumed.

3.1 Numerical simulation

In the following, we analyze simulation results where we consider a square area of 1000 m by 1000 m. The orientation of the initial principal stresses coincides with the grid boundary. Because of symmetry a quarter of the area is considered with the injection well located in the corner. We assume an initial reservoir pressure of 15 MPa and an initial reservoir temperature of 80°C. The average porosity is assumed 13% and permeability 250 mD. Injected water temperature is assumed to equal 15°C. In the simulated cases different injection rate and initial stress in reservoir were assumed.

In first case near to isotropic state of stress was assumed with $\sigma_{max} = 42.4$ MPa and $\sigma_{min} = 42$ MPa. In second case the assumed initial stress was: $\sigma_{max} = 42.4$ MPa and $\sigma_{min} = 28.2$ MPa. For isotropic initial state of stress calculations were done for injection rate 150, 200, 300 and 500 m^3/hr; for anisotropic case assumed injection rate was 300 m^3/hr.

Figure 2 show well pressure change in time for the cases analyzed. Higher injection rate requires higher injection pressure, what results in faster and further growing fracture. Injection flow rate of 150 m^3/hr causes fracturing of rock after 600 days of injection, 200 m^3/hr bring fracturing after 200 days. For injection rate higher than 300 m^3/hr fracture is created very fast. After fracture creation it is visible big pressure drop when pressure decreases from P_{fi} to P_f. After that some stabilization is observed what is connected with assumed boundary conditions.

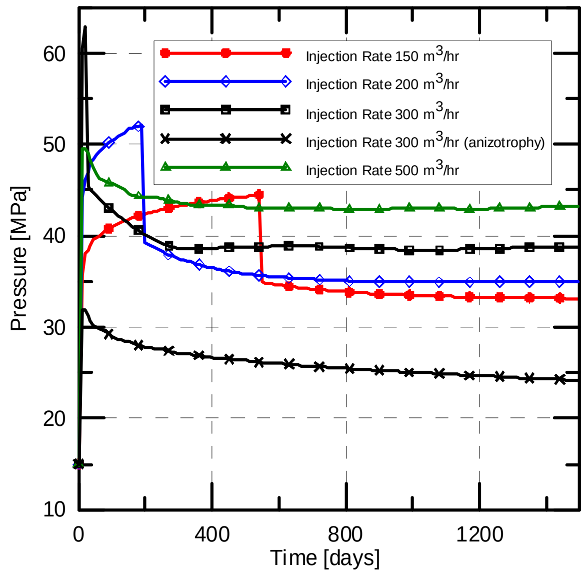

Figure 2: Well pressure.

Figure 3 shows fracture length increase in time. For two small injection rates small fracture length increasing can be observed. For high injection rates fracture growth continuously.

Figure 4-5 shows pressure, temperature incremental and absolute stress after 1500 days of injection with 300 m3/hr injection rate for isotropic initial state of stress. On figures 6-7 those parameters for anisotropic initial state of stress are shown.

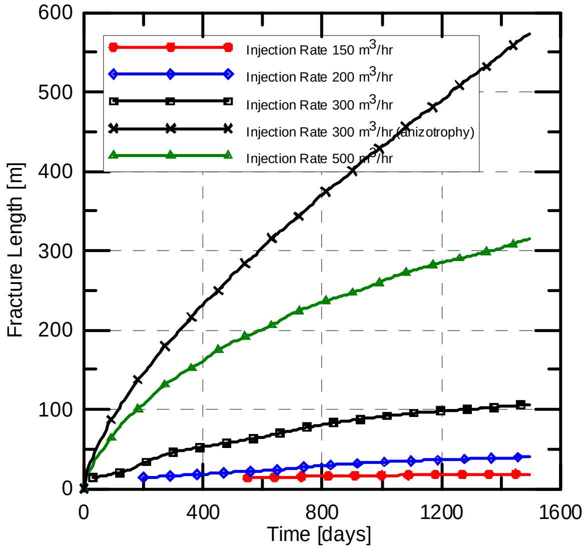

Figure 3: Fracture length.

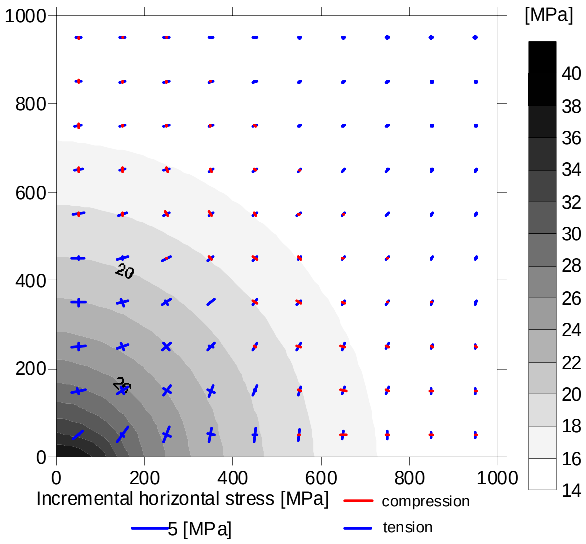

Figure 4: Pressure and incremental stress field after 1500 days of injection for isotropic initial state of stress.

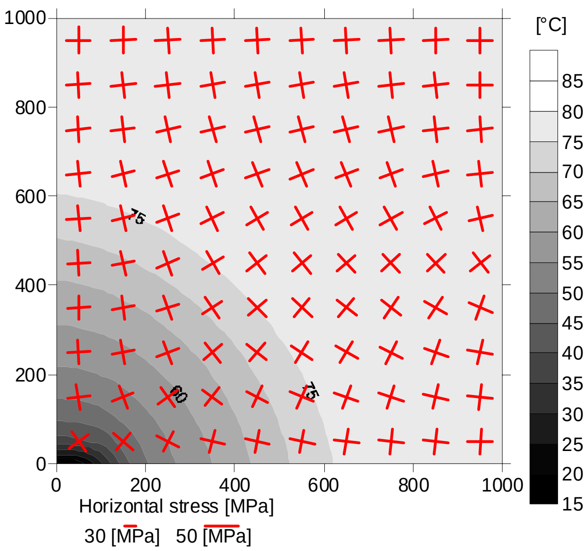

Figure 5: Temperature and absolute stress field after 1500 days of injection for isotropic initial state of stress.

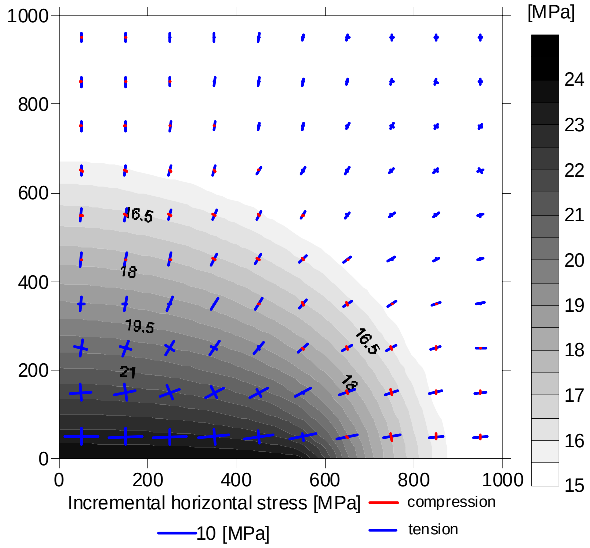

Figure 6: Pressure and incremental stress field after 1500 days of water injection for anisotropic initial state of stress.

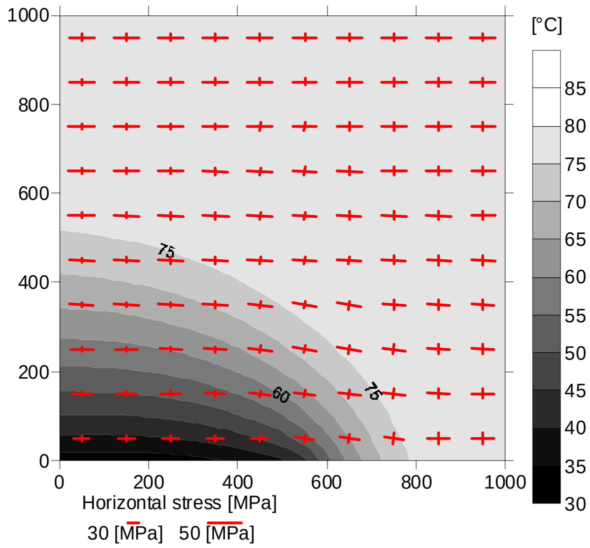

Figure 7: Temperature and absolute stress field after 1500 days of water injection for anisotropic initial state of stress.

As expected, the greatest temperature-change occurs in the near-well region. Cooling of the formation (by the cold injected water) results in tensile stress development, which overcomes the incremental compressive stresses resulting from the injection-induced fluid-pressure increase. The cooling effect can bring the reservoir closer to fracturing conditions. Analysis of the simulation runs suggests the possibility of local stress reorientation (which depends on the relative magnitude of the stress perturbations compared to the initial state of stress). A comparison of those two cases shows big influence of stress anisotropy on fracture propagation which impact on cold front movement. It shows how important is determination of initial state of stress in reservoir.

4. CONCLUSION

Formations with tight/low permeability are the primary candidates for stress sensitive behaviour and fracturing during cold water injection.

A numerical model to determine the impact of injection on geomechanical behavior of a geothermal reservoir and fracture propagation has been developed.

Compared with the conventional isothermal or thermal reservoir simulators, description of the flow- and thermal-induced evolution/distribution of reservoir stresses is the unique feature of the simulator presented here. Simulation results show that the thermal-induced stresses overcome the incremental compressive stresses resulting from the injection-induced fluid-pressure increase. The thermal stresses alter the in-situ stress anisotropy in both magnitude and direction.

Estimation of geothermal reservoir stresses enables to determine optimal injection rate to avoid rock fracturing (and early cold water breakthrough) in geothermal management. The analysis of geomechanical behaviour of geothermal reservoir presented in the paper can be used to predict hydraulic fracture propagation due to cold water injection. A 3-D model extension could deliver more detailed information about mechanical behaviour of a rock.

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