ANALYSIS OF INDUCED SEISMICITY AND HEAT TRANSFER

IN GEOTHERMAL RESERVOIRS BY COUPLED SIMULATION

A Dissertation in
Energy and Mineral Engineering
by
Quan Gan

© 2015 Quan Gan

Submitted in Partial Fulfillment
of the Requirements
for the Degree of

Doctor of Philosophy

August 2015
The dissertation of Quan Gan was reviewed and approved* by the following:

Derek Elsworth  
Professor of Energy and Geo-Environmental Engineering  
Dissertation Advisor  
Chair of Committee

Jamal Rostami  
Associate Professor of Energy and Mineral Engineering

Shimin Liu  
Assistant Professor of Energy and Mineral Engineering

Tong Qiu  
Associate Professor of Civil Engineering

Luis F. Ayala H.  
Professor of Petroleum and Natural Gas Engineering;  
Associate Department Head for Graduate Education

*Signatures are on file in the Graduate School
ABSTRACT

Massive water injection during the stimulation and production stages in geothermal reservoirs is able to induce strong coupled response. Fracture properties may be significantly altered due to fluid transport, heat transfer, and chemical reactions. The constitutive relationships governing the transport of mass, heat, deformation, and chemical reaction are defined by various parameters, including permeability, porosity, temperature, and local stress state. One of the purposes of this study is to investigate the principal factors including the thermal, hydraulic, and mechanical effects in inducing the reactivation of pre-existing fractures. The seismicity induced from the reactivation of fractures and faults is influenced and triggered by different processes at different length and timescales. We explore these effects related to the timing of seismicity and the roles or effective stresses and thermal stresses in fractured reservoirs including the use of reactivation to control permeability evolution in a manner beneficial to thermal recovery in EGS reservoirs.

This dissertation comprises four chapters and an appendix.

In Chapter 1 we explore the propagation of fluid pressures and thermal stresses in a prototypical geothermal reservoir containing a centrally-located critically-stressed fault from a doublet injector and withdrawal well to define the likelihood, timing and magnitude of events triggered by both fluid pressures and thermal stresses. We define two bounding modes of fluid production from the reservoir. For injection at a given temperature, these bounding modes relate to either low- or high-relative flow rates. At low relative dimensionless flow rates the pressure pulse travels slowly, the pressure-driven changes in effective stress are muted, but thermal drawdown propagates through the reservoir as a distinct front. This results in the lowest likelihood of pressure-triggered events but the largest likelihood of late-stage thermally-triggered events. Conversely, at high relative non-dimensional flow rates the propagating pressure pulse is larger and migrates more quickly through the reservoir but the thermal drawdown is uniform across the reservoir and
without the presence of a distinct thermal front, and less capable of triggering late-stage seismicity.

In Chapter 2 we develop a dimensionless model to predict the thermal drawdown response, and quantify the relationship between the timing and magnitude of late stage seismic event and the induced thermal stress from thermal drawdown. We evaluate the uniformity of thermal drawdown as a function of a dimensionless flow rate $Q_d$ that scales with fracture spacing $s (m)$, injection rate $q (kg/s)$, and the distance between the injector and the target point $L^* (Q_d \propto qs^2 / L^*)$. By assuming the dominant heat transfer by heat conduction within the fractured medium, this model is either capable to predict the timing of induced seismicity by the thermal stress by the analytical formula.

Due to the significant influence of fracture network geometry in heat transfer and induced seismicity, a discrete fracture network model is developed (Chapter 3) to couple stress and fluid flow in a discontinuous fractured mass represented as a continuum by coupling the continuum simulator TF\_FLAC$^{3D}$ with cell-by-cell discontinuum laws for deformation and flow. Both equivalent medium crack and permeability tensor approaches are employed to characterize pre-existing discrete fractures. The evolution of fracture permeability accommodates stress-dependent aperture under different stress states, including normal closure, shear dilation, and for fracture walls out of contact under tensile loading.

This discrete fracture network model is applied (Chapter 4) in a generic reservoir with an initial permeability in the range of $10^{-17}$ to $10^{-16}$ $m^2$, fracture density of $\sim 0.09m^{-1}$ and fractures oriented such that either none, one, or both sets of fractures are critically stressed. For a given reservoir with a pre-existing fracture network, two parallel manifolds are stimulated that are analogous to horizontal wells that allow a uniform sweep of fluids between the zones. The enhanced connectivity that develops between the production zone and the injection zone significantly
enhances the heat sweep efficiency, while simultaneously increasing the fluid flux rate at the production well. For a 10m deep section of reservoir the resulting electric power production reaches a maximum of 14.5 MWe and is maintained over 10 years yielding cumulative energy recoveries that are a factor of 1.9 higher than for standard stimulation. Sensitivity analyses for varied fracture orientations and stimulation directions reveal that the direction of such manifolds used in the stimulation should be aligned closely with the orientation of the major principal stress, in order to create the maximum connectivity.

In the appendix, we explore a new mechanism in determining the breakdown pressure. Experiments on finite-length boreholes indicate that the breakdown pressure is a strong function of fracturing fluid composition and state as well. The reasons for this behavior are explored including the roles of different fluid types and state in controlling the breakdown process. The interfacial tension of the fracturing fluid is shown to control whether fluid invades pore space at the borehole wall and this in turn changes the local stress regime hence breakdown pressure. Interfacial tension is modulated by fluid state, as sub- or supercritical, and thus gas type and state influence the breakdown pressure.
The chapters and appendix in this dissertation corresponds with a series of five papers either published or in-submittal. Based on the chronological order in this work, these papers are:

   [http://dx.doi.org/10.1016/j.petrol.2015.01.011](http://dx.doi.org/10.1016/j.petrol.2015.01.011).


TABLE OF CONTENTS

LIST OF FIGURES .................................................................................................................. ix

LIST OF TABLES ..................................................................................................................... xv

ACKNOWLEDGEMENT .......................................................................................................... xvi

Chapter 1 Analysis of Fluid Injection-Induced Fault Reactivation and Seismic Slip in Geothermal Reservoirs ........................................................................................................... 1

Abstract ................................................................................................................................. 1
  1 Introduction ........................................................................................................................ 2
  2 Model setup ........................................................................................................................ 3
    2.1 Analytical stress analysis ......................................................................................... 4
    2.2 TOUGH-FLAC simulator introduction ............................................................... 6
    2.3 Fault modeling approach ...................................................................................... 7
    2.4 Moment magnitude scaling ............................................................................... 8
    2.5 Model configuration ............................................................................................ 9
  3 Validation result .............................................................................................................. 11
  4 Parametric analysis ....................................................................................................... 13
    4.1 Fault permeability ........................................................................................... 13
    4.2 Fractured medium permeability ........................................................................ 14
    4.3 Injection temperature ....................................................................................... 16
    4.4 Fracture spacing ............................................................................................. 21
    4.5 Stress obliquity .............................................................................................. 25
  5 Conclusions .................................................................................................................. 26
  6 References .................................................................................................................... 27

Chapter 2 Thermal Drawdown and Late-Stage Seismic Slip Fault-Reactivation in Enhanced Geothermal Reservoirs ................................................................................................. 31

Abstract ................................................................................................................................. 31
  1 Introduction .................................................................................................................... 32
  2 Mathematical formulation .......................................................................................... 34
  3 Model description ....................................................................................................... 38
  4 Thermal drawdown behavior .................................................................................... 40
  5 Thermal front propagation and induced seismicity .............................................. 44
  6 Output power optimization ..................................................................................... 55
  7 Conclusions ............................................................................................................... 57
  8 Acknowledgement ..................................................................................................... 59
  8 Reference .................................................................................................................. 59

Chapter 3 A Continuum Model for Coupled Stress and Fluid Flow in Discrete Fracture Networks ................................................................................................................................. 63

Abstract ................................................................................................................................. 63
  1. Introduction ............................................................................................................... 64
  2. Constitutive model development ....................................................................... 67
LIST OF FIGURES

Figure 1-1. Fault plane stress analysis and slip failure mechanism by fluid pressurization. ...4

Figure 1-2 Flac-Tough model simulation flow chart [Taron and Elsworth, 2009] ...............6

Figure 1-3 Available approaches for fault modeling in TOUGHREACT. .........................8

Figure 1-4 (a) Model geometry and applied stress boundary condition, initial condition, (b) strike-slip fault geometry in model.................................................................10

Figure 1-5 Spatial distribution of the fault failure potential, \( J \) under isothermal injection .12

Figure 1-6 Response at control points (a) located at mid length on the fault and (b) resulting fault slip distance distribution for cases both before and after slip. (c) Evolution of Coulomb stress ratio at mid length along the fault. (d) Slip distance along the fault under isothermal injection.................................................................13

Figure 1-7 (a) Fault slip distance distribution comparison under different fault permeability (b) fault pore pressure evolution comparison under different fault permeability. .................................................................14

Figure 1-8 Fault seismic slip event timing vs. magnitude under different fracture permeabilities (b) fault pore pressure evolution under different fracture permeabilities.................................................................16

Figure 1-9 Two fault seismic slips occurred within 20 years induced by H-M effect and by cooling stress effect. (a) The evolution of fault Coulomb stress ratio. (b) Slip distance evolution of both footwall (green line) and hanging wall (blue line). ...............17

Figure 1-10 (a) Fault shear stress (blue) and fault temperature drawdown gradient (red) evolution (b) the evolution of fault temperature +(blue) (c) comparison of fault thermal drawdown gradient under different water injection temperatures ( \( T = 50^\circ C, 100^\circ C, 150^\circ C \)) .................................................................19

Figure 1-11 Field x-displacement distribution for isothermal injection and cold injection at \( t = 10^9 s \) ........................................................................................................20

Figure 1-12 Fault seismic event magnitude and timing result comparison under different injection temperature 50°C, 100°C, 150°C, 250°C. The arrows in left direction show the results of event magnitude, and the arrows in right direction shows the results of event timing.................................................................21

Figure 1-13 (a) Reservoir temperature evolution under fracture spacing=10 m. (b) reservoir temperature evolution under fracture spacing=50 m, (c) reservoir
temperature under fracture spacing=100 m, (d0 fault temperature evolution under 10m-50m-100m fracture spacing. ..........................................................23

Figure 1-14 Fault seismic slip event magnitude and timing comparison under different fracture spacing (injection temperature T= 50 C). ..........................................................24

Figure 1-15 (a) Fluid temperature distribution at 4.4 years and 31 years under different fracture spacing (10m-50m-100m) under the same injection pressure, (b) domain temperature comparison at 4.4 year under different fracture spacing (10m-50m-100m) (b) domain stress Szz at 4.4 year under different fracture spacing. .......................24

Figure 1-16 (a) Schematic figure of different fault inclination angles (b) Fault seismic slip moment magnitude comparison under different fault inclination angles...............25

Figure 2-1 Schematic of analytical heat conduction within fractured medium, the identical fractures with aperture b are equally separated at the spacing s.........................35

Figure 2-2 (a) Model geometry and applied stress boundary condition, initial condition, (b) strike-slip fault geometry in model..........................39

Figure 2-3 Dimensionless fault temperature $T_d$ evolution vs dimensionless time $t_d/Q_d$ under $Q_d$ values varies respectively from $2.6 \times 10^{-6}$ to $2.6 \times 10^4$.................................42

Figure 2-4 Dimensionless fault temperature $T_d$ at the fault vs dimensionless time $t_d$ under $Q_d$ varies respectively from $2.6 \times 10^{-6}$ to $2.6 \times 10^4$ .........................44

Figure 2-5 Thermal front propagation from the injection well (right axis) towards the production well (left axis) under different $Q_d$ values, the figures from (a) to (f) respectively represent the $Q_d$ values varied from $2.6 \times 10^{-6}$ to $2.6 \times 10^4$.........................46

Figure 2-6 Validation of the dimensionless timing equation for the onset of seismicity between numerical simulation results and the analytical results under various $Q_d$ values ($Q_d = 2.6 \times 10^{-4} \sim 2.6 \times 10^2$). Red circles represent the velocity results from the analytical equation, while the black squares represent the results from the simulations. ..........................................................48

Figure 2-7 Comparison of water temperature evolution in the reservoir under two bounding $Q_d$ values, the left side figures represent the condition of $Q_d = 2.6 \times 10^4$, the right side figures represent the condition of $Q_d = 2.6 \times 10^{-3}$ .........................49

Figure 2-8 Contour of rock temperature distribution at $t = 1.0 \times 10^6 s, 1.0 \times 10^7 s, 1.0 \times 10^8 s$ respectively for $Q_d = 2.6 \times 10^4$ (a) and $Q_d = 2.6 \times 10^{-3}$ (b). (c) represents the evolution of the coulomb stress ratio under $Q_d = 2.6 \times 10^4$ and $Q_d = 2.6 \times 10^{-3}$ with isothermal or non-isothermal injection conditions..........................................................51
Figure 2-9 (a) the comparison of slip distance distributions in different patches along the fault under the different dimensionless flow rate $Q_D$, (b) the corresponding maximum magnitude of seismicity based on the slip distance results under different flow rate $Q_D$. ..........................................................53

Figure 2-10 (a) The fault temperature evolution under $Q_D = 2.59 \times 10^{-8}$, the two dashed lines represent the area affected by the thermal stress acting on the fault when slip occurs at $6.2 \times 10^{7} \, s$, (b) the fault temperature evolution under $Q_D = 2.59 \times 10^{3}$, the two dashed lines at the two tips of fault shows the fault regime affected by the thermal stress due to the cooling. ..........................................................55

Figure 2-11 The results of power generation rate calculation under different $Q_D$ values within 50 years injection, the magenta curve represents the smallest $Q_D = 2.6 \times 10^{-6}$, and the green curve represents the largest $Q_D$ value equal to $2.59 \times 10^{9}$. .........................57

Figure 3-1 The impact of initial aperture in the relationship between normal stress and fracture aperture. ..................................................................................................................71

Figure 3-2 Fracture normal dilation displacement evolution induced from the shear slip in fracture. ..................................................................................................................72

Figure 3-3 Fracture aperture evolution under different normal stress state. .........................73

Figure 3-4 Equivalent continuum simulation workflow implementation in TF FLAC3D ......76

Figure 3-5 Reservoir configuration for injection inside a 39 m long fracture within an infinite medium. ..................................................................................................................77

Figure 3-6 Fracture aperture evolution comparisons against other discontinuum models. .....78

Figure 3-7 Evolution of fracture injection pressures evaluated by various models. .............81

Figure 3-8 Evolution of injection pressure for isothermal injection (black line) and non-isothermal injection (red line). ..........................................................................................82

Figure 3-9 Evolution of fracture normal aperture for isothermal injection (black line) and non-isothermal injection (red line), respectively..........................................................82

Figure 3-10 Evolution of fracture normal stress under isothermal injection (black line) and non-isothermal injection (red line). ........................................................................82

Figure 3-11 Aperture distribution along the fracture at 72 days and 180 days under conditions of both isothermal injection and non-isothermal injection.................................83

Figure 3-12 Schematic of two sets of orthogonal fracture ubiquitously distributed in a 200m × 200m × 10m reservoir..........................................................85
Figure 3-13 Validation of fracture aperture at the injection well between the developed equivalent continuum TF_FLAC$^{3D}$ and the original continuum TFREACT [Taron et al., 2009] ...............................................................................................................................86

Figure 3-14 Validation of injection pressure between the developed equivalent continuum TF_FLAC$^{3D}$ and the original continuum TFREACT ...............................................................................................................................86

Figure 3-15 (a) Locations of starting points and ending points for the two sets of fractures in the reservoir, (b) lognormal probability distribution for the length of fractures, (c) distribution of fracture networks in a 200 m x 200mx 10m reservoir, fractures in red are oriented at 135 degrees, and those in green are oriented at 020 degrees (with respect to the North)...............................................................................................................................89

Figure 3-16 Power law relationships between the fracture length and initial fracture aperture...............................................................................................................................90

Figure 3-17 (a) Fracture pressure distribution for the base case at 180 days, (b) contour of fracture mean permeability, (c) shear stress drop along the first fracture set, (d) shear stress drop along the second set of fractures...............................................................................................................................91

Figure 3-18 Fracture aperture distributions for the two sets of fractures under constant stress ratio at 180 days respectively ...............................................................................................................................94

Figure 3-19 Evolutions of fracture permeability around the injector under the fixed stress ratio within 180 days .................................................................95

Figure 3-20 Evolution of fracture permeability ratio $k_x$ over $k_y$ under different stress difference ...............................................................................................................................95

Figure 3-21 Evolution of fracture aperture for the two sets of fracture with increasing stress difference. Normal closure is the dominating response as deviatoric stress increased. Fracture aperture in set 1 is larger than the set 2 ................................................................................................................96

Figure 3-22 Contour of fracture networks under different orientations representing the fractures oriented at 020-135 degrees, 060-120 degrees, and 015-165 degrees with respect to the North separately ............................................................................................................................97

Figure 3-23 Fracture aperture comparisons at 180 days between different fracture orientations at 020-135 degrees, 060-120 degrees, and 015-165 degrees with respect to North ........................................................................................................................................98

Figure 4-1 (a) Discrete fracture network distribution with orientations striking 045 and 120 degrees with respect to the North, (b) a second discrete fracture network distribution with orientations at 020 and 135 degrees with respect to the North. These two orientations are chosen to evaluate the impact of fracture network geometry on fluid flow and heat transport .................................................................................................................................112

Figure 4-2 Schematic of injection and production design, (a) stimulate the producer zone and injector zone separately at 20 kg/s in W-E direction, (b) stimulate the reservoir
in N-S direction at 20 kg/s, (c) the eventual production design including two injection well at C and D points at constant pressure 15 MPa, and two production wells at A and B points at constant pressure 7 MPa. .......................................................................................... 115

Figure 4-3 Contour plots of equivalent rock mass permeability evolution, (a) initial fracture permeability distribution for fractures oriented 045 – 120, (b) initial fracture permeability distribution for the scenario of fractures oriented 020 – 135, (c) development of two interconnected manifolds after the E-W stimulation for fractures oriented 045 – 120, (d) fracture permeability distribution after the E-W stimulation for fractures oriented 020 – 135 degrees...................................................................................................... 117

Figure 4-4 Comparison of total electric power generation from two production wells between all five cases. The magenta curve (Case 4) is for fractures oriented 045 – 120 degrees with E-W stimulation and this returns the highest electric power generation. Case 3 shown by the blue curve for fractures oriented 020 – 135 degrees but without stimulation indicates the lowest power generation. ................................................................. 118

Figure 4-5 Evolution of flow rate and water temperature (enthalpy) in the two production wells. Plots in the left column (a, c, e, g, i) represent the flow rate evolution in the two production wells for the five cases (1-5), plots in the right column (b, d, f, h, j) represent the evolution of water temperature in the two production wells respectively. ......................................................................................................................... 120

Figure 4-6 Contour of rock temperature distribution at $t = 6.34 \text{ years}$, (a) Case 1 fracture orientations 020 – 135 degrees after E-W stimulation, (b) Case 2 fracture orientations 020 – 135 degrees after N-S stimulation, (c) Case 3 without stimulation, (d) Case 4 fracture orientations 045 – 120 degrees after E-W stimulation, (e) Case 5 fracture orientations 045 – 120 degrees with friction angle 035 – 75 degrees after E-W stimulation. ................................................................................................................................. 122

Figure 4-7 (a) Distribution of fracture networks in the reservoir oriented at 045 and 120 degrees respect to the North with 250 Fractures $\rho_f = 0.0223 \text{ m}^{-1}$ in each set, (b) contour of initial fracture permeability before stimulation................................................................................................................................. 123

Figure 4-8 Power generation evolution comparisons between the Case 4 with 1000 fractures $\rho_f = 0.089 \text{ m}^{-1}$ and the case with 500 fractures $\rho_f = 0.0223 \text{ m}^{-1}$ ................................................................. 124

Figure 4-9 Evolution of water enthalpy at the production well between Case 4 with high fracture density $\rho_f = 0.089 \text{ m}^{-1}$ and the lower fracture density Case $\rho_f = 0.0223 \text{ m}^{-1}$ ......................................................................................................................................................... 125

Figure 4-10 Contour of rock temperature at $t = 2.0 \times 10^8 \text{s}$ for the lower fracture density case $\rho_f = 0.0223 \text{ m}^{-1}$ ......................................................................................................................................................... 126

Figure A-1 Workflow initiating from the injection of fluids in PMMA. The final conclusions are highlighted in the blue rectangle. ........................................................................................................................................ 137
Figure A-2 (a) Schematic of PMMA specimen used in the experiment. The drilled borehole is located in the center of sample and terminates in the center of the cube. (b) Biaxial loading frame. Beryllium-copper load cells measure the applied force. PMMA cube is centered between the rams and attached to a pore pressure line with access through the front face of the cube. (c) Resulting longitudinal fracture in the PMMA sample parallel to the borehole direction. (d) Induced transverse fracture perpendicular to the drilled borehole in the PMMA sample.

Figure A-3 Injected fracturing fluid state and properties under experiment condition. The fluid states are divided into subcritical state (left) and supercritical (right).

Figure A-4 Experiment results of fracture breakdown pressure under various injected fracturing fluid under the same experiment conditions (Alpern 2012).

Figure A-5 2-D Model geometry (left) created in simulations, and applied hydraulic and displacement boundary conditions and initial conditions (right).

Figure A-6 Validation of 2-D tangential effective stress around borehole with various Biot coefficient factor (0.3~1).

Figure A-7 Evolution of longitudinal fracture breakdown pressure coefficient with different Biot coefficients under various Poisson ratio (0~0.5) in permeable rocks.

Figure A-8 Validation of 2-D longitudinal stress under different Biot coefficient factor (0.2~1).

Figure A-9 Evolution of 2-D transverse fracture breakdown pressure coefficient under different Biot coefficient factor with Poisson’s ratio ranging from 0.1~0.5 (longitudinal stress).

Figure A-10 3-D model geometry with boundary condition (left), and mesh with finite borehole length condition (right).

Figure A-11 Spatial distribution of longitudinal stress over fluid pressure for Biot coefficient equals to 0.9 (top) and 0 (down) respectively.

Figure A-12 Summaries of critical pressure vs. breakdown pressure under different invasion pressure Pc value.

Figure A-13 Distribution of ratio about invasion pressure to the interfacial tension under different fracturing fluids.

Figure A-14 Validations of 3-D permeable and impermeable breakdown pressure analytical solutions with experiment data.
LIST OF TABLES

Table 1-1 Material properties input in model [Rutqvist et al., 2013] ............................................ 10

Table 2-1 Material properties input in the model for host rock and fault [Gan and Elsworth, 2014].................................................................................................................................40

Table 2-2 $Q_p$ values for the fault under different reservoir configurations by variant injection rate and fracture spacing combinations. ............................................................................. 43

Table 3-1 Data used in the simulation [McTigue, 1990]........................................................................... 79

Table 3-2 Sensitivity tests of applied stress boundaries in the fracture aperture evolution. .... 92

Table 4-1 Rock and fracture properties used in the simulation. ...............................................................111

Table 4-2 Case studies designed in the study for different stimulation – production scenarios................................................................................................................................. 114

Table A-1 Hydraulic boundary and stress / displacement boundary applied in the COMSOL simulations................................................................................................................................. 145

Table A-2 PMMA properties used in the simulation................................................................................146

Table A-3 Comparison of supercritical / subcritical fluid interfacial tension (Berry 1971) .... 157

Table A-4 Breakdown pressure results in hydro-fracture experiment of Argon (Ar) injection under different confining stress from 5 MPa ~ 60 MPa .................................................... 158

Table A-5 Summary if expressions for breakdown pressure in different cases, i) permeable / impermeable medium, ii) fracture geometry, longitudinal / transverse........ 159
ACKNOWLEDGEMENT

First of all, I would like to express my deepest gratitude to my advisor, Derek Elsworth. It is my greatest fortune to work in this group for my Ph.D. In the past three years, he gave me tremendous help in how to perform scientific research, teach me the philosophy in how to be an excellent researcher in the science-wise and life-wise. I will always be grateful for his kind support and patience during my Ph.D. time. His philosophy and faith will keep influencing and helping me in my future career life.

I would like to thank my committee members: Shimin Liu, Don Fisher, Jamal Rostami, and Tong Qiu for taking their kind time in reviewing the manuscript, and proposing constructive suggestions in my work. And also they gave me great help in referring my application in the academic job, teaching me how to be a successful researcher. I sincerely thank them for their help.

I am grateful to my former and current colleagues at the G3 group for all the discussions and suggestions in solving my research problems, like Josh Taron, Yi Fang, K.J., and Baisheng Zheng etc. I would like to express the special gratitude to Josh Taron. He gave me significant help in solving the code problems.

Lastly, I thank my parents and my wife Yi Zhang for their selfless and unconditional help in supporting me finish the research work in the past years.
Chapter 1

Analysis of Fluid Injection-Induced Fault Reactivation and Seismic Slip in Geothermal Reservoirs

Abstract

We explore the issue of fault reactivation induced in Enhanced Geothermal Systems (EGS) by fluid injection. Specifically we investigate the role of late stage activation by thermal drawdown. A THM (Thermal-Hydrological-Mechanical) simulator incorporating a ubiquitous joint constitutive model is used to investigate the elastic-plastic behavior of an embedded fault. We apply this new THM model to systematically simulate the seismic slip of a critically-stressed strike-slip fault embedded within the reservoir. We examine the effects of both pore pressure perturbation and thermal shrinkage stress on the magnitude of the resulting events and their timing. We analyze the sensitivity of event magnitude and timing to changes in the permeability of the fault and fractured host, fracture spacing, injection temperature, and fault stress obliquity. From this we determine that: (1) the fault permeability does not affect the timing of the events nor their size, since fluid transmission and cooling rate is controlled by the permeability of the host formation. (2) When the fractured medium permeability is reduced (e.g. from $10^{13}$ to $10^{16} \ m^3$), the timing of the event is proportionately delayed (by a corresponding three orders of magnitude), although the magnitude of the seismic event is not impacted by the change in permeability. (3) Injection temperature has little influence on either the timing or size of the early hydro-mechanically induced events, but it does influence the magnitude but not the timing of the secondary thermal event. The larger the temperature differences between that of the injected fluid and the ambient rock, the larger the magnitude of the secondary slip event. (4) For equivalent
permeabilities, changing the fracture spacing (10m-50m-100m) primarily influences the rate of heat energy transfer and thermal drawdown within the reservoir. Smaller spacing between fractures results in more rapid thermal recovery but does not significantly influence the timing of the secondary thermal rupture.

1 Introduction

Massive water injection has the potential to elevate pore pressures within porous and fractured formations and to reactivate faults, either seismically or aseismically [Cappa, 2010; Cappa and Rutqvist, 2012; Cappa et al., 2009; Scholz, 1990; Segall and Rice, 1995]. Extensive studies have explored the response of injection-induced activity in enhanced-geothermal systems (EGS): some evidence shows that the stress perturbation and the elevation of fluid pressures may induce distributed seismic events on fractures [Zoback and Harjes, 1997]. However, reactivation, especially on large faults, may result in large seismic events [Garagash and Germanovich, 2012], depending on the weakening characteristics of the feature [Miller, 2004; Segall and Rice, 1995]. Possible mechanisms of fault reactivation are not limited to hydro-mechanical effects. In geothermal systems where the reservoir is chilled with the forced-circulation of cold fluid, the induced thermal shrinkage stress will also control changes in effective stress and may cause fault activation and induced seismicity [Rutqvist and Oldenburg, 2007; Rutqvist et al., 2008]. Stresses reduce as convective transport drains heat from the rock matrix and it thermally shrinks and decompresses along the unloading curve according to the equivalent elastic properties of the fractured medium [Bažant et al., 1979; Boley, 1960; Sandwell, 1986]. Since energy release is proportional to fracture aperture to the third power - representing the effective volume destressed by the slip - large faults are of significant concern when understanding reactivation. Large faults (finite-thickness) typically have a specific architecture
including heterogeneous properties of a fault core zone and damage zone [Caine, 1996] that exert a strong influence on fluid transport behavior. This includes a low permeability fault core that is a flow barrier across the fault and flanked by higher (than the host) permeability zones [Faulkner et al., 2003; Kim et al., 2004; Vermilye and Scholz, 1998]. The fault core is typically gouge-filled with low permeability (in the range $1.0 \times 10^{-17}$ to $1.0 \times 10^{-21} \text{ m}^2$). Significantly, the impermeable fault acts as a barrier to prevent water from penetrating through the fault although fault-parallel transmission is possible. Fault reactivation is a complex process involving the interaction of total stresses and fluid pressures and transformations in stiffness and permeability. In this work we focus on the additional impact of delayed thermal stresses on the timing and magnitude of any induced instability.

We use a coupled Thermal-Hydrological-Mechanical (THM) model [Taron and Elsworth, 2009; 2010] to explore the different factors governing fault reactivation of a critically-stressed strike-slip fault. The critical controlling parameters that are examined include fault permeability, fractured medium permeability, fracture spacing and stress obliquity relative to the fault. Finally we control the temperature of the injected water as a method to scale the impact of thermal effects.

2 Model setup

In order to investigate the influence of fluid pressures and thermal stresses on the reactivation of critically-stressed faults, we analyze anticipated stress changes using a simple model for a fault acted upon by far-field stresses. This defines the stress drop, which in turn may be used to define the seismic energy release and related event magnitude. We then follow the development of stresses around faults oriented with different stress obliquities using a suitable simulator that
couples the effects of fluid transport and changes in total stresses. This method is used to evaluate the timing and magnitude of the resulting slip events.

### 2.1 Analytical stress analysis

Normally, fault instability is governed by contemporary principal stress orientations relative to the pre-existing fault planes [Streit and Hillis, 2004]. Based on effective stress theory and the Coulomb failure criterion, the basic equation for slip on a plane is defined as,

\[ \tau = C + \mu_s (\sigma_n - p) = C + \mu_s \sigma_{n_{eff}} \]  

where \( C \) is the cohesion, \( p \) is the fluid pressure, \( \mu_s \) is the coefficient of friction, \( \sigma_n \) is the normal stress and \( \tau \) is the shear stress [Scholz, 1990].

To allow the analysis of failure due to an applied oblique stress on the failure of a pre-existing fault [Jaeger, 1979] the effective normal stress \( \sigma_{n_{eff}} \) and shear stress \( \tau \) along the fault may be defined as (see Figure. 1-1),

![Fault plane stress analysis and slip failure mechanism by fluid pressurization.](image)

\[ \sigma_{n_{eff}} = \frac{\sigma_x + \sigma_y}{2} + \frac{\sigma_x - \sigma_y}{2} \cos \left( \frac{\pi}{2} - \theta \right) - \tau_{xy} \sin \left( \frac{\pi}{2} - \theta \right) - p \]  

(2)
\[
\tau = \frac{\sigma_s - \sigma_y}{2} \sin 2\left(\frac{\pi}{2} - \theta\right) - \tau_{sy} \cos 2\left(\frac{\pi}{2} - \theta\right)
\]  

(3)

To allow stability to be determined when combined with the strength criterion,

\[
\tau_s = \sigma_{neff}^* \mu^*_s
\]  

(4)

This enables strength of a rock mass incorporating a single plane of weakness to be straightforwardly evaluated [Jaeger, 1979]. Where we assume that failure may occur on the most critically oriented plane (Figure 1-1 b) then the ratio of maximum and minimum principal effective stresses is given by [Rutqvist et al., 2007]

\[
\frac{\sigma_1^*}{\sigma_3^*} = \frac{\sigma_1 - \alpha p}{\sigma_3 - \alpha p} \leq q = \left[ (\mu_i^2 + 1)^{1/2} + \mu_s \right]^2
\]  

(5)

where \(q\) represents the effective stress limiting difference ratio, where we adopt Biot effective stress theory [Biot, 1941] to calculate the horizontal effective maximum in-situ and minimum in-situ stress. When the left hand side ratio exceeds \(q\), then the fault begins to slip. In our study, the Biot coefficient is set as 0.8, the internal fault friction angle is equal to 28 degrees and therefore \([Biot, 1941; Byerlee, 1978]\), so the value of \(q\) is 2.76, and the friction angle of the intact host rock is 30 degrees, then the corresponding value \(q\) is 3. Correspondingly, for the stress regime of \(\sigma_1 = 45.5MPa, \sigma_3 = 28.6MPa, p = 18.1MPa\) the stress obliquity is,

\[J = \sigma_1^*/\sigma_3^* = 2.2 < q = 2.76.\]

Therefore the fault is set as initially stable, while critically stressed. An approach to describe the fault slip potential could use the parameter \(\Delta\),

\[\Delta = \Delta \sigma_1^*/2.76 \Delta \sigma_3^*\]  

(6)

where \(\Delta \sigma_1^*\) represents the change in maximum principal effective stress and \(\Delta \sigma_3^*\) is the change in minimum principal effective stress.

In this work, the failure potential is estimated using a friction angle of 28° and zero cohesion, therefore failure occurs when the effective stress ratio \(J = \sigma_1^*/\sigma_3^*\) is greater than 2.76.
2.2 TOUGH-FLAC simulator introduction

We use a coupled THMC model [Taron and Elsworth, 2009] capable of representing the mechanical response of the fractured porous subsurface due to fluid injection and recovery. This model satisfies the requirement of representing the coupled elastic-plastic behavior of the fault. The simulator couples analysis of mass and energy transport in porous fractured media (TOUGH) and combines this with mechanical deformation (FLAC3D) as noted in Figure 1-2 [Xu et al., 2003; Xu et al., 2004; Xu et al., 2001]. The same meshes are used for each of these codes although TOUGH has block-centered nodes and FLAC3D nodes at the block corners (see Figure 1-2). Thus interpolation is required between pressures defined in the transport model to be applied as effective stresses in the mechanical code (TOUGHREACT). Evolving effective stresses are used, together with an appropriate constitutive model to define the evolution of fracture apertures in the medium and to thereby determine the change in permeability.

Figure 1-2 Flac-Tough model simulation flow chart [Taron and Elsworth, 2009]
2.3 Fault modeling approach

Generally there are three approaches to model fault characteristics [Cappa, 2010; J Rutqvist, Y.-S. Wu, C.-F. Tsang and G. Bodvarsson, 2002]: the fault could be characterized as a mechanical interface with zero-thickness, by representation with solid elements and double interfaces, or by combination of solid elements and ubiquitous joints as weak plane (see Figure 1-3). Fault modeling as an interface could be an appropriate approach if the thickness of the fault is negligible compared to the scale of the entire reservoir. To successfully couple fault slip with fluid pressurization in an interface model, it is necessary to add hydraulic elements along the interface, because the hydraulic elements must update the effective normal stress and shear strength by interpolating accurate fault pressure. However, this approach is difficult in building the fault gridding in TOUGH; and it cannot model the heterogeneous character of the fault. The continuum approach with a ubiquitous joint constitutive model in FLAC3D is easier in building meshes for TOUGH; furthermore this approach can represent the anisotropic plasticity of the fault by accounting for the presence of a weak plane. Therefore we adopt this third approach to model the fault.
2.4 Moment magnitude scaling

The seismic energy released by shear slip on a pre-existing fault plane is quantified by the event moment $M_0$. The moment magnitude scale $M_s$ is used to measure the strength of the seismic event. The $M_s - M_0$ relationship is defined [Kanamori and Abe, 1979; Purcaru and Berckhemer, 1982] as,

$$\log M_0 = 1.5M_s + 16.1$$

(7)

where $M_0$ is seismic moment and $M_s$ is moment magnitude.
The moment \( M_0 \) is also defined by the relation [Aki, 1967],

\[
M_0 = \mu LWD_c
\]

where \( L= \) fault length, \( W= \) fault rupture width, \( \mu= \) rigidity, \( D_c= \) slip distance .

The fault seismic moment is a function of slip distance and fault rigidity when the fault rupture area is constant. Since the different patches on the fault undergo different slip distances due to the decaying propagation of the rupture front along the fault, we define the moment by the following equation,

\[
M_0 = \int_0^L \mu LWD_c
\]

In order to obtain moment magnitudes that are appropriate to the 3D representation of the fault (fault area of 442m \( \times \) 442m) we use the results from the 2D plane strain model and extrapolate these over the fault area. This switch between the 2D slip model and the 3D fault ignores the clamped boundaries (zero displacement) at the top and base of the fault and would slightly overestimate the moment magnitude – relative to the real case where the edges of the fault are clamped.

2.5 Model configuration

The model is used to represent conditions prototypical to an enhanced geothermal system (EGS). The reservoir geometry is a pseudo 3-D doublet (1500m \( \times \) 600m \( \times \) 15m) (see Figure 1-4). The initial temperature distribution is homogeneous with an initial rock temperature of 250 C. The minimum in-situ stresses are imposed at 28.8 MPa in the W-E direction, and maximum in-situ stresses are subjected to a constant 45 MPa in the N-S direction. A strike-slip fault is located in the center of reservoir with the injection well and withdrawal well distributed to the east and west of the fault, respectively. In this configuration the fault acts as a barrier for the propagation of the
fluid front from the injection to the recovery well. The model boundaries are set as no-flow boundaries with applied constant stresses.

The strike-slip fault comprises a low permeable core (thickness 0.8m) and flanked by higher permeability damage zones (thickness 1.2 m). The ubiquitous joint model represents the elastic-plastic behavior of the fault. The joints and host rock have the same initial internal frictional angle of $28^\circ$ (see Table 1-1). We adopt a linear strain-softening relationship that implies that the friction angle decreases with an increase in the plastic strain.

![Model geometry and applied stress boundary condition, initial condition, (b) strike-slip fault geometry in model.](image)

**Table 1-1 Material properties input in model [Rutqvist et al., 2013].**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>In-tact rock</th>
<th>Damage zone</th>
<th>Core zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{\text{inj}}$</td>
<td>13.8 MPa</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$P_{\text{rec}}$</td>
<td>18.8 MPa</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$P_{\text{ref}}$</td>
<td>25.8 MPa</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$\sigma_s$</td>
<td>45.5 MPa</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$\sigma_s$</td>
<td>28.6 MPa</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$\sigma_s$</td>
<td>35 MPa</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### 3 Validation result

We use the geometry of Figure 1-4 (a) to validate the model. The simulation results in induced fault seismic slip due to over pressurization by the fluid (2MPa). The parameter $J = \sigma_1' / \sigma_3'$ is utilized to describe the distribution of shear failure potential (see Figure 1-5) around the pressurized fault. When the fault friction angle is equal to 28 degrees, the fault and areas ahead of the tip show a high potential for slip – as illustrated by $J > 2.76$ (Figure 1-5(a)). This strength is applied on the fault, but the strength in the surrounding matrix corresponds to a friction angle equal to 30 degrees with $J = 3$ - that remains unfailed in the matrix. Where strength of the fault is raised to 35 degrees and the analysis completed – the fault is now stable (Figure 1-5(b) with $J > 3.7$ required for failure) despite the same 2MPa over pressurization.

During failure, the control point in the center of the fault has the largest relative seismic slip distance of 0.35 m (see Figure 1-6b). The corresponding seismic moment magnitude is 3.1. When the rupture front migrates away from the center of the fault to the fault tips, the slip distance of each patch decreases. When the slip occurs, the corresponding Coulomb Stress ratio is equal to the tangent of the friction angle $\tan28^\circ$ (see Figure 1-6c).
Figure 1-5 Spatial distribution of the fault failure potential, $J$ under isothermal injection.
Figure 1-6 Response at control points (a) located at mid length on the fault and (b) resulting fault slip distance distribution for cases both before and after slip. (c) Evolution of Coulomb stress ratio at mid length along the fault. (d) Slip distance along the fault under isothermal injection.

4 Parametric analysis

To understand the principal factors that influence event magnitude and timing during fault reactivation, we examine the influence of fault and host permeability, fracture spacing of the host, injection temperature and stress obliquity. These factors are evaluated during the full loading cycle including the influences of fluid pressure and thermal stresses, respectively at early and late times during reservoir production.

4.1 Fault permeability

The hydraulic characteristics of the fault are represented by a low permeability core [Caine, 1996] flanked by damage zones with elevated permeability and embedded within the host
medium of defined intermediate permeability. The permeability of the fault damage zone is varied from $10^{-14}$ m$^2$ to $10^{-17}$ m$^2$, with the fracture permeability of the host is $10^{-14}$ m$^2$.

Figure 1-7a shows the evolution of the fault slip distance at the control point for different fault damage zone permeability values. The overpressure required to induce slip is sensibly constant in all cases (total stresses do not change significantly) and since pressure build-up in the fault is controlled principally by supply of fluid through the moderate permeability ($10^{-17}$ m$^2$) fractured host, then the timing of fault slip is the same for different fault permeabilities. In all cases the slip occurs ~3.9 hours ($1.4 \times 10^4$ s) after the initiation of pumping (see Figure 1-7b).

**Figure 1-7 (a) Fault slip distance distribution comparison under different fault permeability (b) fault pore pressure evolution comparison under different fault permeability.**

### 4.2 Fractured medium permeability

As noted previously, the permeability of the fractured host controls pressure build-up in the system by limiting the supply of fluid to the embedded fault. Thus, where permeability of the host is either initially elevated, or where it is similarly increased by artificial stimulation, then this will influence the rate of fluid supply to the fault. This further modulates the timing of slip. For a
fractured medium the growth in the fracture aperture may be defined by an empirical function of non-linear fracture stiffness $\alpha$ and applied effective stress $\sigma$ [J. Rutqvist, Y.-S. Wu, C.-F. Tsang and G. Bodvarsson, 2002] as,

$$b_m = b_{mr} + (b_{mo} - b_{mr}) \exp(-\alpha \sigma)$$  \hspace{1cm} (10)

where $b_m$ denotes the hydraulic aperture due to mechanical stress effect alone, $b_{mo}$ is the aperture without mechanical stress effect and $b_{mr}$ is the residual aperture solely under the mechanical stress. Assuming the mechanical aperture is approximately equivalent to the hydraulic aperture ($b - b_m$) in an orthogonally fractured medium, then the permeability may be defined as,

$$k = \frac{b^3}{12s} + \frac{b^3}{12s} = \frac{b^3}{6s}$$  \hspace{1cm} (11)

where $s$ is the fracture spacing, and $b$ is fracture aperture. The fracture permeability is dynamic due to controls on the evolution aperture exerted by mechanical stress effects.

We examine the influence of feasible permeabilities of fractured host in the range $10^{-13} - 10^{-16} m^2$ on the magnitude and timing of fault slip where the permeability of the fault damage zone is maintained constant at $10^{-15} m^2$. In all cases the fracture spacing is retained constant at 10 m. Figure 1-8 shows that high fracture permeabilities concomitantly decrease the time taken for the pressure front to arrive at the fault and to build to the required fault reactivation pressure of 20.7 MPa. For this pressure-controlled system the delay in fault reactivation increases by almost an order of magnitude for each one-order decrease in fracture permeability: the fault slips at 0.38 hours ($1.4 \times 10^3 s$) when the host permeability is $10^{-13} m^2$, and three orders of magnitude later 16.2 days ($1.4 \times 10^6 s$) when the host permeability is decreased to $10^{-16} m^2$. However, although slip occurs earlier as the permeability is increased, the relative slip-distance of the fault remains the same – resulting in no change in moment magnitude with this change in host permeability (Figure 1-8(a)).
4.3 Injection temperature

With the prior influence of isothermal injection examined for differences in permeability of both the fault and the host – we now examine the influence of thermal drawdown (non-isothermal injection) on fault reactivation. Specifically we are interested in the potential for late-time reactivation due to the stresses induced by thermal drawdown.

Figure 1-9 confirms that indeed late time seismic events may occur within the 30-year injection history when fluid is injected at 50 °C into a host of 250 °C, where the fracture host permeability is kept as 10^{-14} m^2, and the fault permeability is 10^{-17} m^2. The first seismic slip event occurs due to hydro-mechanical effects at 1.4 \times 10^4 s (3.9 hours), and the second slip occurs at 1.4 \times 10^8 s (4.4 years) when the thermal front arrives at the fault and causes significant temperature drawdown. The magnitude of the second slip event that is induced by the thermal shrinkage stress is weaker than the first event induced by hydro-mechanical effects. The first event has a relative slip
distance of 36 cm and a magnitude of 3.1 with the second event displacing only 6 cm with a magnitude of 2.6.

Figure 1-9 Two fault seismic slips occurred within 20 years induced by H-M effect and by cooling stress effect. (a) The evolution of fault Coulomb stress ratio. (b) Slip distance evolution of both footwall (green line) and hanging wall (blue line).
When the hot reservoir rock is cooled, the thermal stress induced by shrinkage results in unloading by decreasing the maximum in-situ stress; and in turn the fault shear strength decreases. The associated decrease in shear strength in the cooling regime facilitates fault reactivation. Figure 1-10a shows that the seismic slip induced by the thermal stress occurs when the rate of temperature drawdown gradient reached to the maximum point. Figure 1-10c indicates that the maximum drawdown gradient at an injection temperature $T=50 \, ^\circ C$ is a critical transition point for inducing late-stage seismicity. In this particular instance the maximum absolute value of the thermal drawdown gradient is equal to $6 \times 10^{-7} \, ^\circ C/s$. Figure 1-10b shows that the fault temperature begins to be drawn down after $8.0 \times 10^7$ seconds (2.5 years) and this continues until the reservoir is depleted after $1.6 \times 10^9$ seconds (50.7 years).
The effect of the thermal shrinkage stress is most pronounced at the thermal boundary between the hot and cooling regions where stress gradients are largest. Displacements in the direction of the minimum principal stress indicate a net displacement into the cooled region as that region thermally-compacts (see Figure 1-11). Slip occurs when the advancing cooling front reaches the fault and the rate of stress change, both in space and in time, is particularly high (Figure 1-10). Therefore we primarily investigate the influence of injected fluid temperature in the range
50°C – 250°C on the magnitude and timing of fault slip and thermal energy recovery efficiency. Figure 1-12 shows that the timing and magnitude of the first seismic slip event is not affected by the injection temperature, because the hydraulic front diffuses faster than the thermal front, so the first seismic slip event induced by hydraulic-mechanical effects are not affected by the temperature variation of the injected fluid. However, it is observed that only the colder injection (T = 50°C) cause sufficient fault shear strength reduction and in turn slips at t = 1.4 × 10^8 s (4.4 years) and, as expected, the injected fluid with hotter temperature does not generate the later time seismic slip event. The greater temperature difference between the injected fluid and the ambient rock results in larger thermal stress, which reduces the fault shear strength to a larger extent. Thus, only the colder injection leads to a larger seismic fault reactivation.

![Field x-displacement distribution for isothermal injection and cold injection at t = 10^9 s.](image-url)
Fault seismic event magnitude and timing result comparison under different injection temperature 50°C, 100°C, 150°C, 250°C. The arrows in left direction show the results of event magnitude, and the arrows in right direction shows the results of event timing.

4.4 Fracture spacing

The injected fluid flows only in the fractures and the fracture spacing directly controls thermal conduction from the matrix to the fluid in the fractures. Here we investigate the influence of fracture spacing (10m, 50m and 100m) in both fault reactivation and heat energy recovery efficiency, while the fracture permeability is retained constant at $10^{-14}$ m$^2$.

To determine the impact of fracture spacing on thermal recovery and fault slip we compare the results for isothermal injection ($T = 250°C$) to those for cold injection ($T = 50°C$) and with different fracture spacing. Figure 1-14 illustrates that the variation in fracture spacing has no impact on the timing and magnitude of fault reactivation – in all cases the fault slips after ~ $1.4 \times 10^4$ s (3.89 hours) under isothermal injection $T = 250°C$. Similarly, they are unchanged for cold injection - the timing of the second (thermally activated) slip for all the fracture spacing
cases (10m-50m-100m) remains unchanged at \( \sim 1.4 \times 10^8 s \) (4.43 years), and the corresponding seismic moment magnitude is 2.6. Figure 1-13(a) shows that the thermal front propagates uniformly at small fracture spacing (10m) in the reservoir and the second (thermally activated) slip event is triggered as soon as the thermal front arrives at the fault at \( \sim 1.4 \times 10^8 s \) (4.43 years). Conversely, when the fracture spacing is increased to 100m, the reservoir temperature decreases uniformly across the reservoir without the presence of a distinct thermal front. The spatial thermal gradient around the fault is the principal factor to determine whether the second slip event actually occurs (Figure 1-13(b) and (c)). It indicates that the spatial thermal gradient is maximum at \( \sim 1.4 \times 10^8 s \) (4.43 years) and is similar for fracture spacing between 50 m and 100m.

Further investigation of the temperature profiles reveals that the denser fracture spacing increases the residence time of the cold fluid circulating within the hot reservoir and the smaller fracture spacing allows more rapid recovery of heat from the matrix blocks. Figure 15(a) shows the evolution of fluid temperature within the reservoir for different fracture spacing \((T = 50^\circ C)\). As fracture spacing increases the chilled region adjacent to the injector is reduced in size (see Figure 1-15(b)). Thus the more closely-spaced fractures result in a faster recovery of heat from the reservoir.
Figure 1-13 (a) Reservoir temperature evolution under fracture spacing=10 m. (b) reservoir temperature evolution under fracture spacing=50 m, (c) reservoir temperature under fracture spacing=100 m, (d) fault temperature evolution under 10m-50m-100m fracture spacing.
Figure 1-14 Fault seismic slip event magnitude and timing comparison under different fracture spacing (injection temperature T= 50 C).

Figure 1-15 (a) Fluid temperature distribution at 4.4 years and 31 years under different fracture spacing (10m-50m-100m) under the same injection pressure, (b) domain temperature comparison at 4.4 year under different fracture spacing (10m-50m-100m) (b) domain stress $S_{zz}$ at 4.4 year under different fracture spacing.
4.5 Stress obliquity

Fault orientation plays an important role in modulating the stress state on the fault plane and in controlling the fluid over-pressurization required for fault reactivation. We compare different fault orientation scenarios while maintaining the distance between the fault center and injection well as constant. During this the fault plane angle is varied from 30 degrees to 75 degrees (see Figure 1-16(a)).

The fault is stable when the fault is inclined at only 30 degrees, but fails with the largest slip distance (6 cm) and moment magnitude (2.5) occurring after $1.4 \times 10^4 \text{s} \ (3.9 \text{ hours})$ when inclined at 60 degrees to the minimum principal stress (Figure 1-16(b)). This is for H-M effects only.

![Schematic figure of different fault inclination angles](image1.png)

![Fault seismic slip moment magnitude comparison under different fault inclination angles](image2.png)

Figure 1-16 (a) Schematic figure of different fault inclination angles (b) Fault seismic slip moment magnitude comparison under different fault inclination angles.
5 Conclusions

We explore the potential for reactivation of a major strike-slip fault in an enhanced geothermal systems (EGS) reservoir. We systematically investigate the mechanisms causing fault reactivation and seismic slip together with the critical controlling factors influencing slip magnitude and timing. The results indicate the primary influence of mechanical and hydrological effects in the short-term fault reactivation, and the impact of thermal stress in causing long-term seismic slip. The timing and magnitude of the initial H-M slip is insensitive to the permeability of the fault. This is because the transmission of fluid to the fault, from the injection well, is controlled by the permeability of the stimulated host medium. When the host fracture permeability is constant, the progression of the stress ratio between injection and fault due to hydraulic effect is similar in the magnitude and timing. Increasing the permeability of the host by an order of magnitude decreases the time to the first H-M event by an order of magnitude. For equivalent permeabilities, the rate of thermal recovery is controlled by the fracture spacing. Smaller fracture spacing results in faster thermal drawdown and more rapid energy recovery.

However, in terms of cold water injection, the induced thermal shrinkage stress does play an important role in unloading of the stress field by reducing the maximum in-situ stress, and thereby reduce the shear strength. This stress change is shown to result in secondary seismic slip, even when no strengthening of the fault is considered. The magnitude of the second seismic slip event is governed by the temperature difference between the injected fluid temperature and the ambient domain temperature. This is because the magnitude of thermal shrinkage stress is also proportional to the temperature difference. The larger temperature difference leads to a larger late stress ratio rise. In our results, where cold fluid is injected at 50 C, this results in a late stage event of M_s=2.6 with a seismic slip distance of 6 cm. The fracture spacing does not affect the timing and magnitude of seismic slip when the permeability of the fractured medium is retained.
constant. This is surprising as the effectiveness of energy recovery and therefore the rate of cooling is increased with a decrease in fracture spacing. However this does not significantly affect the timing of these secondary thermal events (Figure 1-14). Finally, the orientation angle of the fault directly determines the stress state applied by the injected fluid and controls the magnitude of the resulting event, but not its timing. Faults with the largest stress obliquity fail with the largest moment magnitude.

Acknowledgement

This work is the result of partial support from the US Department of Energy under project DOE-DE-EE0002761. This support is gratefully acknowledged.

6 References


Cappa, F. (2010), Modeling of coupled deformation and permeability evolution during fault reactivation induced by deep underground injection of CO2, edited.


Chapter 2

Thermal Drawdown and Late-Stage Seismic Slip Fault-Reactivation in Enhanced Geothermal Reservoirs

Abstract

Late-stage seismic-slip in geothermal reservoirs has been shown as a potential mechanism for inducing seismic events of magnitudes to ~2.6 as late as two decades into production. We investigate the propagation of fluid pressures and thermal stresses in a prototypical geothermal reservoir containing a centrally-located critically-stressed fault from a doublet injector and withdrawal well to define the likelihood, timing and magnitude of events triggered by both fluid pressures and thermal stresses. We define two bounding modes of fluid production from the reservoir. For injection at a given temperature, these bounding modes relate to either low- or high-relative flow rates. At low relative dimensionless flow rates the pressure pulse travels slowly, the pressure-driven changes in effective stress are muted, but thermal drawdown propagates through the reservoir as a distinct front. This results in the lowest likelihood of pressure-triggered events but the largest likelihood of late-stage thermally-triggered events. Conversely, at high relative non-dimensional flow rates the propagating pressure pulse is larger and migrates more quickly through the reservoir but the thermal drawdown is uniform across the reservoir and without the presence of a distinct thermal front, and less capable of triggering late-stage seismicity. We evaluate the uniformity of thermal drawdown as a function of a dimensionless flow rate $Q_D$ that scales with fracture spacing $s$ (m), injection rate $q$ (kg/s), and the distance between the injector and the target point $L'$ ($Q_D \propto qs^2/L'$). This parameter enables the reservoir characteristics to be connected with the thermal drawdown response around the fault.
and from that the corresponding magnitude and timing of seismicity to be determined. These results illustrate that the dimensionless temperature gradient adjacent to the fault $\frac{dT_D}{dx_D}$ is exclusively controlled by the factor $Q_D$. More significantly, this temperature gradient correlates directly with both the likelihood and severity of triggered events, enabling the direct scaling of likely magnitudes and timing to be determined a priori and directly related to the characteristics of the reservoir. This dimensionless scaling facilitates design for an optimum $Q_D$ value to yield both significant heat recovery and longevity of geothermal reservoirs while minimizing associated induced seismicity.

1 Introduction

Harvesting geothermal energy from deep fractured low-permeability formations has become a feasible method to ease the demand on fossil energy. Predicting mass rates and temperatures of fluid production and assessing induced seismicity are intimately connected topics that require an intimate and complete understanding of subsurface coupled THMC (Thermal-Hydrological-Mechanical-Chemical) processes [Taron and Elsworth, 2010]. The associated thermal drawdown response of the rock mass results from the circulation of a heat-transfer fluid [Bodvarsson, 1969; Bödvarsson and Tsang, 1982]. Thermal drawdown in the fractured porous medium may be determined by accommodating the essential components of the reservoir – heat transfer from the reservoir matrix to the fluid by conduction and then advection across the reservoir – for which a variety of analytical approaches are available [Elsworth, 1989a; b; 1990; Ganguly and Mohan Kumar, 2014; Gringarten and Witherspoon, 1973; Gringarten et al., 1975; Pruess, 1983; Pruess and Wu, 1993; Ghassemi et al., 2003]. These approaches are based on the assumptions of locally
1-D heat conduction in an infinite medium, and that the fluid flow in the fractured medium instantaneously reaches local thermal equilibrium [Shaik et al., 2011].

To accommodate more general flow geometries, including the inclusion of heterogeneity, a variety of numerical methods are available to represent response. Such models also accommodate key process of heat transfer in the subsurface in accommodating dual porosity to describe heat exchange between the porous fracture and the low porosity rock [Xu et al., 2003; Xu et al., 2004; Xu et al., 2001; Elsworth, 1989a, 1989b; Elsworth and Xiang, 1989]. The principal heat transfer processes include first heat conduction between the matrix and fluid within the fractures then the advection of that heat across and then out from the reservoir. Depending on the fluid velocity in the fracture, the temperature gradient between the circulating fluid and the adjacent rock varies significantly. In general, the amount of heat energy transferred from the rock is controlled by the heat transfer area, the temperature difference between rock and fluid and the velocity of the circulating fluid [Holman, 2002].

In addition to exploring thermal drawdown in the reservoir, and its influence on effluent fluid temperatures, the spatial distribution of reservoir temperature is also influenced by rates of fluid circulation. This thermal drawdown of the rock is also capable of inducing thermal stresses, which in turn are implicated in the potential for induced seismicity and increase the likelihood of late stage fault reactivation [Gan and Elsworth, 2014]. The role of thermal stresses in reservoirs has been explored with respect to the evolution of permeability [Elsworth, 1989] and of stresses [Segall and Fitzgerald, 1998]. Thermally-driven tress changes in geothermal reservoirs are known to be potentially significant. In this work we specifically explore rates of stress generation and their propagation through the reservoir as controlled by thermal capacitance of a dual porosity system, and ultimately on the potential to develop unstable slip. In this, the induced thermal stresses cause the unloading of the fault by reducing maximum in-situ stress, thereby reducing shear strength and therefore enabling slip reactivation as a potentially seismic event. The
severity of the reactivation event appears directly related to the spatial gradient of rock
temperature that develops in the reservoir [Gan and Elsworth, 2014] — a uniform reduction in
temperature will have a muted change in thermal stresses. Hence, in this work we explore the
impact of fluid circulation rates on the heterogeneity of thermal drawdown that may develop
within the reservoir and its potential impact on the timing and magnitude of induced seismicity.
The following develops a dimensionless semi-analytical model which incorporates the reservoir
scale, fracture spacing and injection mass flow rate to determine thresholds for the evolution of
uniform or shock-front distributions of thermal drawdown within the rock comprising the
reservoir. The semi-analytical model is derived based on the balance of heat conduction within
the fractured medium and the Warren-Root fracture model. Key variables are prescribed that may
then be used to assess the propagation of stress fronts through the reservoir and from that define
the likelihood, timing and magnitude of late stage events that might occur on reactivated faults.

2 Mathematical formulation

To assess and elucidate the fundamental heat transfer processes within the fractured-porous
medium, a basic model is presented in Figure 2-1 for the following analytical study. The two-
dimensional reservoir is characterized by an orthogonal fracture network with uniform fracture
spacing $s$ (m) in both $x$ and $z$ directions and with a uniform fracture aperture $b$ (m). The fractures
are the sole conduits for fluid circulation within the reservoir. This parallel fracture model (PFM)
has been validated to effectively characterize heat recovery from an arrangement of prismatic
blocks, which are thermally isolated from the geologic host medium [Elsworth, 1990].
Figure 2-1 Schematic of analytical heat conduction within fractured medium, the identical fractures with aperture $b$ are equally separated at the spacing $s$.

Here we relax the restrictions imposed by prior analytical solutions by imposing the following assumptions:

1. The initial temperature of the reservoir and interstitial fluid is uniform at $T_0$ with cold water injected at constant rate and at constant temperature $T_{inj}$.

2. Heat conduction occurs primarily in $z$-directions along the fractures with thermal conductivity $K_f$ and with heat transfer in the vertical direction neglected. We assume that the majority of heat transfer occurs normal to the direction from injection well to production well. There is no heat transfer by radiation within the fractures. The diffusion of heat in the rock matrix occurs only in the direction orthogonal to the fracture plane.

3. The density and heat capacity for both the rock and fluid are constant. Also the thermal conductivity of the rock matrix is assumed constant.
The differential equations governing heat transfer in the fracture are based on the balance of heat energy in the control volume of fractures, defined as

\[ \rho_c \frac{\partial T_w(x,t)}{\partial t} = -\nu \rho_c \frac{\partial T_w(x,t)}{\partial x} + \frac{2K_r}{b} \frac{\partial T_r(x,z,t)}{\partial z} \bigg|_{z=b/2} \]  

(1)

where \( \nu \) is the fluid velocity (m/s), \( T_w(x,t) \) is the temperature of water, \( T_r(x,z,t) \) is the temperature of the rock matrix, \( b \) is the fracture aperture (m), \( c_w \) is the heat capacity of water (J/kg°C), \( \rho_w \) is the density of water, and \( K_r \) is the thermal conductivity of the rock (J/s/m°C).

The temperature of the rock matrix is governed by the one-dimensional heat conduction equation:

\[ \frac{\partial^2 T_r(x,z,t)}{\partial z^2} = \frac{\rho_r c_r \partial T_r(x,z,t)}{K_r \partial t} \]  

(2)

where \( \rho_r \) is the density of the rock matrix, and \( c_r \) is the heat capacity of the rock.

The thermal drawdown response may be determined under a variety of different reservoir configurations by using a unified dimensionless analytical model. We redefine the governing equations in terms of the non-dimensional variables of dimensionless flow rate, \( Q_D \), mean temperatures of the rock, \( T_{D,r} \), and water, \( T_{D,w} \), time, \( t_D \) and length scales, \( x_D \) and \( z_D \), as

\[ Q_D = \frac{\rho_c c_w q_i}{K_r s \left( \frac{L'}{L} \right)^s} \]  

(3)

\[ q_i = \frac{q}{\frac{W}{s}H} = \frac{q_s}{\rho_w HW} \]  

(4)

where \( q \) is the injection rate (kg/s), \( q_i \) is the volumetric flow rate per fracture per unit thickness (m³/s), the terms \( H \) and \( W \) are the height and width of the reservoir respectively and \( L' \) is the distance between the injector and the target point. Substituting equation (4) into equation (3) defines the dimensionless flow rate as,
\[ Q_D = \frac{q_s^2 c_w}{K_r H L W} \] (5).

Dimensionless time \( t_D \) is defined as,
\[
t_D = \frac{\rho_w c_w \rho_r c_r}{K_r} \left( \frac{q_1}{L'} \right)^2 t = \frac{t}{K_r \rho_r c_r \left( \frac{q_s c_w}{H W L} \right)^2} \] (6).

The dimensionless rock temperature \( T_{D_r} \) is defined as,
\[
T_{D_r} = \frac{T_{inj} - T_r}{T_{inj} - T_0} \] (7).

The dimensionless outlet water temperature \( T_{D_w} \) is defined as,
\[
T_{D_w} = \frac{T_{inj} - T_w}{T_{inj} - T_0} \] (8).

The dimensionless lengthscales \( x_D \) and \( z_D \) are defined separately as,
\[
x_D = \frac{x}{L'} \] (9)
\[
z_D = \frac{z}{s} \] (10).

\[
\eta_w = \frac{L' K_r}{\nu \rho_w c_w s b} = \frac{1}{Q_D} \] (11).

These defined non-dimensional parameters, \( Q_D \), \( t_D \), \( T_{D_r} \), \( T_{D_w} \), lengthscales \( x_D \) and \( z_D \) are used to transform and simplify the governing equations. By assuming that heat storage term in the fracture is negligible, the corresponding dimensional governing equations of (1) and (2) could be represented in dimensionless form as,
\[
\frac{\partial T_{D_w}(x,t)}{\partial x_D} = 2\eta_w \left. \frac{\partial T_{D_w}(x,z,t)}{\partial z_D} \right|_{z=b/2} \] (12).
\[
\frac{\partial^2 T_{D_w}(x,z,t)}{\partial z_D^2} = \eta_w \frac{\partial T_{D_w}(x,z,t)}{\partial t_D} \] (13).
3 Model description

This present work is a continuation of prior characterizations that defines the potential for late-stage fault reactivation in geothermal reservoirs [Gan and Elsworth, 2014]. This extension is to codify the likelihood, timing and magnitude of potential events as a function of fracture geometry and fluid transmission characteristics and applied flow-rates. The heat transfer problem is approached using semi-analytical and numerical methods and this then applied to define the propagation of stress fronts and their impact on seismicity. Calculations are completed using a numerical simulator that couples the analysis of mass and energy transport in porous fractured media (TOUGH) with mechanical deformation (FLAC3D) [Taron and Elsworth, 2009; 2010; Xu et al., 2004]. These analyses are completed using the non-dimensional parameters noted in equation (5) through (8).

The reservoir geometry includes a 2-D rectangular (1500m × 600m × 15m) reservoir containing three sets of orthogonal fractures (see the mesh in Figure 2-2). A strike-slip fault is located in the center of reservoir flanked by equidistant injection and withdrawal wells. The initial distribution of reservoir temperature is uniform with an initial rock and fluid temperature of 250 °C, an initial reservoir pressure of 18.8 MPa, and with cold water injected under constant mass flow rate with a constant enthalpy of $2.0 \times 10^5 \, J/kg$ (equivalent to 43 °C) and with the production well operated under a constant pressure of 13.8 MPa. A minimum in-situ stress of 28.8 MPa is imposed in the W-E direction and the maximum horizontal stress of 45 MPa is applied in the N-S direction. The model boundaries are set as no-flow boundaries with applied constant stresses.

The inserted strike-slip fault is finely discretized to represent the anticipated mechanical and transport characteristics of a fault with a low permeability core (thickness 0.8m) flanked by higher permeability damage zones (thickness 1.2 m). The fault acts as flow conduit along its axis but as a barrier/impediment for the propagation of the fluid front from the injection to the
recovery well. A ubiquitous-joint constitutive model is applied to represent the elastic-plastic behavior of the fault. The fractures comprising the fracture network and host rock have the same initial angle of internal friction of $30^\circ$ (see Table 2-1) [Biot, 1941; Byerlee, 1978]. The friction angle of the fault joint is $30^\circ$. We adopt a linear strain-softening relationship that implies that the friction angle decreases with an increase in the plastic strain.

Fluid and heat transport is accommodated by representing the reservoir as an equivalent dual permeability continuum. This dual porosity model accommodates the local thermal disequilibrium in heat exchange between rock matrix and fluid in fractures. The dual permeability
continuum is represented by orthogonal fracture sets spaced equally in the three principal directions and with uniform initial aperture and with a functionally impermeable matrix.

Table 2-1 Material properties input in the model for host rock and fault [Gan and Elsworth, 2014].

<table>
<thead>
<tr>
<th>Parameters</th>
<th>In-tact rock</th>
<th>Damage zone</th>
<th>Core zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Young’s modulus (GPa)</td>
<td>8</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>Shear modulus (GPa)</td>
<td>5.5</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Permeability (m²)</td>
<td>1×10⁻¹⁶</td>
<td>5×10⁻¹³</td>
<td>1×10⁻¹⁷</td>
</tr>
<tr>
<td>Poisson’s ratio</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td>Friction angle</td>
<td>30</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
</tr>
<tr>
<td>Fracture permeability (m²)</td>
<td>1×10⁻¹³</td>
<td>5×10⁻¹³</td>
<td>1×10⁻¹⁷</td>
</tr>
<tr>
<td>Cohesion (MPa)</td>
<td>8</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Tensile strength (MPa)</td>
<td>10</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

4 Thermal drawdown behavior

Since the thermal stresses that are induced adjacent to the fault zone may cause seismic fault reactivation, we follow temperature change in the rock using the dimensionless parameters noted earlier. This analysis focuses on predicting the evolution of temperature in the rock (as opposed to fluid temperature as in many prior models [Gringarten et al., 1975; Elsworth, 1990]), and captures the intrinsic relationship between the evolution of dimensionless fault rock temperature
and dimensionless time \( t_D \) under various dimensionless flow rates \( Q_D \). Moreover, complementary evaluations of water outflow temperature condition the utility of the reservoir for heat mining where magnitudes of flow rates, \( Q_D \), are selected to minimize seismic risk.

The evolution of dimensionless fault rock temperature \( T_D \) versus dimensionless time \( t_D/Q_D \) is determined for different dimensionless flow rates \( Q_D \) as shown in Figure 2-3. This is for fracture network permeability of \( 1.0 \times 10^{-15} m^2 \) but with different fracture spacing \( s \) to allow the full parameter space of \( Q_D \) to be explored. Apparent is that the thermal drawdown response of the rock is exclusively controlled by the magnitude of \( Q_D \). Table 2-2 presents the various \( Q_D \) values under different combinations of injection rate and fracture spacing, respectively. Here the main assumption for the expression of \( Q_D \) is that the direction of heat conduction in the matrix is orthogonal to the direction of the transverse fractures.

Figure 3 shows that the drawdown gradients of dimensionless temperature with time become infinite as represented by a steep (vertical) drawdown response around \( t_D/Q_D \sim 1 \), when the \( Q_D \) value decreases below \( 2.6 \times 10^{-4} \). Solutions are limited to this magnitude due to advection-dominant instabilities in TOUGH (Peclet Number > \( 2.6 \times 10^5 \)) with the dashed line in Figure 3 extrapolating this response. Furthermore, the drawdown response becomes asymptotic to \( t_D/Q_D \sim 1 \) as \( Q_D \) approaches \( 2.6 \times 10^{-6} \) defining the lower bounding condition where a plug thermal front migrates through the reservoir and consequently yields the highest thermal gradients in space. Conversely, for high \( Q_D \), the gradient of dimensionless temperature drawdown becomes progressively flatter as the flow rate is increased. When \( Q_D \) reaches \( 2.6 \times 10^4 \), the curves become asymptotic to a horizontal line anchored at \( T_D \sim 1 \). This represents the case where water flow through the reservoir is sufficiently rapid that heat transfer from the rock to the fluid is
small. This results in a uniform temperature distribution in the fluid and uniform thermal drawdown in the reservoir.

Figure 2-3 Dimensionless fault temperature $T_D$ evolution vs dimensionless time $t_D/Q_D$ under $Q_D$ values varies respectively from $2.6 \times 10^{-6}$ to $2.6 \times 10^{4}$.

Thus the bounding distributions of temperature in the reservoir and how they change with time are conditioned by this non-dimensional flow variable, $Q_D$. At high flow rates ($Q_D > 2.6 \times 10^4$) there is little heat transfer from the rock to the water, and the thermal drawdown in the reservoir is uniform as shown in Figure 2-5. Conversely, when the flow rate is low ($Q_D < 5.2$) then the chilled front in the rock propagates through the reservoir.

An alternate way to represent the transient response of the temperature at the fault within the reservoir by the dimensionless timing $t_D$ alone. This dimensionless relationship $T_D - t_D$ returns a
new response of the thermal drawdown in the rock (Figure 2-4). The individual drawdown curves are parallel for \( Q_D < 5.2 \). The factor \( Q_D \) has an impact in determining the sequence of the parallel curves with a steep decline in time. The curve with the lowest \( Q_D = 2.6 \times 10^{-6} \) indicates the earliest drawdown in dimensionless time as \( t_D = 10^{-5} \). For this \( Q_D \)-controlled thermal drawdown system, as the \( Q_D \) value grows one order of magnitude when \( Q_D < 5.2 \), the corresponding timing of drawdown is equivalently elevated by one order magnitude. When the \( Q_D > 5.2 \), the gradient of the rock temperature curves decrease gradually as the \( Q_D \) value grows, which represents the case of more significant heat transfer by heat advection. By means of this dimensionless type curve, the timing of thermal drawdown for reservoirs under different configurations may be rigorously explored.

Table 2-2 \( Q_D \) values for the fault under different reservoir configurations by variant injection rate and fracture spacing combinations.

<table>
<thead>
<tr>
<th>Injection rate (kg/s)</th>
<th>Fracture spacing (m)</th>
<th>( Q_D )</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>1000</td>
<td>2.6\times10^4</td>
</tr>
<tr>
<td>10</td>
<td>1000</td>
<td>2.6\times10^3</td>
</tr>
<tr>
<td>100</td>
<td>100</td>
<td>2.6\times10^2</td>
</tr>
<tr>
<td>50</td>
<td>100</td>
<td>1.3\times10^2</td>
</tr>
<tr>
<td>25</td>
<td>100</td>
<td>6.5\times10^1</td>
</tr>
<tr>
<td>200</td>
<td>10</td>
<td>5.2</td>
</tr>
<tr>
<td>100</td>
<td>1</td>
<td>2.6\times10^2</td>
</tr>
<tr>
<td>100</td>
<td>0.1</td>
<td>2.6\times10^4</td>
</tr>
<tr>
<td>100</td>
<td>0.01</td>
<td>2.6\times10^{-6}</td>
</tr>
</tbody>
</table>
5 Thermal front propagation and induced seismicity

The migration of the thermal front within the reservoir depicts the efficiency of heat recovery from the surrounding geologic medium and controls the form of the thermal gradient at the front. Furthermore, the propagation of the thermal front under different non-dimensional flow rates $Q_0$ alters the timing of its arrival and therefore the timing of any induced seismicity associated with that thermal stress. Importantly, two bounding behaviors are noted, based on the magnitude of the non-dimensional injection rate, $Q_0$. When $Q_0$ is sufficiently large, the advective heat transfer within the fast flowing fluid is much more efficient than that due to conductive heat transfer to the fluid. In this instance the thermal front propagates from the injection well towards the production well without the presence of distinct uniform thermal front – indeed, in the limit, the

![Figure 2-4 Dimensionless fault temperature $T_D$ at the fault vs dimensionless time $t_D$ under $Q_0$ varies respectively from $2.6 \times 10^{-6}$ to $2.6 \times 10^4$.](image)
water temperature is near uniform throughout the reservoir. Conversely, for small $Q_b$ the short dimensionless conduction length in the blocks results in more efficient transfer by heat conduction and results in a distinct front but one that displaces at a slower rate $v_r$ – a velocity $v_r = \frac{\rho_w c_w}{\rho_r c_r} v_w$, defined by the product of the ratio of the thermal capacities of water and rock and the fluid velocity $v_w$ in the fracture.

Figure 2-5 shows the displacement of the thermal front within the rock as non-dimensional flow rates $Q_b$ are varied. The injection well is to the left (x=0 m) with the production well to the right (x=900 m). The fault is intermediate (dashed arrow) between the injection and production wells. If the $Q_b$ value is larger than $2.6 \times 10^2$ (Figure 2-5c), the rock temperature across the entire reservoir declines uniformly. The flat and uniform drawdown curve corresponds to the larger magnitudes of $Q_b$ (Figure 2-5a). Uniform longitudinal thermal drawdown of the rock results in the early breakthrough of cold water (Figure 2-5a). Conversely, when the $Q_b$ values are smaller than $2.6 \times 10^{-2}$, the thermal front propagates as a thermal shock. Figure 2-5f with the smallest $Q_b$ value of $2.6 \times 10^{-6}$ shows the slowest rate of propagation of the thermal front which identifies the case for the most delayed breakthrough. This represents the case that is most desired in retaining outlet temperatures the highest although flow rates may not be sufficiently high to be economically viable as a geothermal reservoir.
Figure 2-5 Thermal front propagation from the injection well (right axis) towards the production well (left axis) under different $Q_D$ values, the figures from (a) to (f) respectively represent the $Q_D$ values varied from $2.6 \times 10^{-5}$ to $2.6 \times 10^{4}$. 
The dimensionless form of timing of the onset of seismicity is linked to the arrival of this front at the location of the fault. This arrival time for the front, traveling a distance $L^*$ at a propagation velocity $v_T$ is

$$t_{\text{seismic}}^{\text{analytical}} = \frac{L^*}{v_T} = \frac{L^*}{\frac{\rho_w c_w}{\rho_m c_m} v_w} = \frac{L^*}{\rho_w c_w} \frac{\rho_m c_m}{v_w}$$

(14).

Since, the dimensionless time is defined as,

$$t_D = \frac{t}{K_r \rho_r c_r} \left( \frac{q s c_w}{H W L^*} \right)^2$$

then substituting the dimensional time of equation (2) into equation (3) gives the timing of seismicity as $t_D \sim Q_D$ (for $Q_D < 10^6$). The relationship between the dimensionless timing for the onset of seismicity and the fluid velocity could be obtained by inserting $t_{\text{seismic}}^{\text{analytical}}$ into the equation of dimensionless time,

$$t_D^{\text{seismic}} = \frac{L^*}{v_w} \frac{\rho_r c_r}{\rho_w c_w} \frac{1}{K_r \rho_r c_r} \left( \frac{q s c_w}{H W L^*} \right)^2 = \frac{L^*}{v_w} \frac{K_r}{\rho_w c_w} \frac{Q_D^2}{s^2}$$

(15).

Therefore the term $t_D^{\text{seismic}} = \frac{L^*}{v_w} \frac{K_r}{\rho_w c_w} \frac{Q_D^2}{s^2}$ in equation (15) could be used to capture the dimensionless timing of seismicity. Figure 2-6 shows that this timing relation is correct for $Q_D < 5.2$ where the injected fluid is able to completely deplete the heat from the reservoir adjacent to the injection well. When the value of $Q_D$ is gradually increased above 5.2, then heat transfer by rapid advection dominates over conduction. In this condition there is no distinct thermal front to change the stress state of the fault and the error in the prediction of timing from this simple relationship $t_D \sim Q_D$ becomes more significant.
From the form of the rate of propagation of the cooling front within the reservoir it is apparent that the non-dimensional timing of arrival of the front scales with dimensionless flow rate (Figure 2-3). There is a linear relationship implied between $Q_D$ and the corresponding timing of seismicity $t_D$ (Figure 2-6). As the magnitude of $Q_D$ increases from $2.6 \times 10^{-6}$, the dimensionless timing $t_D$ for the thermally-driven induced seismicity increases approximately linearly – enabling timing to be defined in a quantitative manner.

Figure 2-6 Validation of the dimensionless timing equation for the onset of seismicity between numerical simulation results and the analytical results under various $Q_D$ values ($Q_D = 2.6 \times 10^{-8} \sim 2.6 \times 10^2$). Red circles represent the velocity results from the analytical equation, while the black squares represent the results from the simulations.

Figure 2-7 illustrates the thermal evolution of water temperature under the two bounding magnitudes of $Q_D$ as $2.6 \times 10^4$ and $2.6 \times 10^{-6}$ respectively. At high dimensionless flow rate the cold front reaches the production well after $1.0 \times 10^7$ s (~120d). At low dimensionless flow rates (
$Q_0 = 2.6 \times 10^{-3}$) the outlet remains at the ambient temperature of the reservoir. This illustrates that geothermal production under large $Q_D$ values may not be feasible as the advection dominated flow results in premature breakthrough, thus degrading the thermal output for the entire reservoir.

Figure 2-7 Comparison of water temperature evolution in the reservoir under two bounding $Q_0$ values, the left side figures represent the condition of $Q_0 = 2.6 \times 10^4$, the right side figures represent the condition of $Q_0 = 2.6 \times 10^{-3}$.

The thermal front propagation under various magnitudes of $Q_D$ substantially changes the evolution of the stress state around the fault. Figure 2-8 illustrates the thermal evolution of rock temperature under the two bounding magnitudes of $Q_D$ as $2.6 \times 10^4$ and $2.6 \times 10^{-3}$. This contrasts with Figure 7 for the evolution of water temperature distribution. For $Q_D = 2.6 \times 10^{-3}$, the rock and fluid are in thermal equilibrium with no significant temperature difference. A
distinct thermal front develops to differentiate the cooled and hot region. Conversely, for $Q_D = 2.6 \times 10^4$ no distinct and observable thermal front develops. Also shown is the evolution of the Coulomb stress ratio ($\tau / \sigma_{\text{eff}}$) in Figure 2-8(c). This shows that the stress state of the fault evolves significantly differently due to the bounding styles of thermal propagation in the reservoir at $Q_D > 2.6 \times 10^4$ and $Q_D < 2.6 \times 10^{-3}$. These induced thermal stresses may trigger fault reactivation when the fluid pressures alone are insufficient. We explore this in the following section.
Figure 2.8 Contour of rock temperature distribution at $t = 1.0 \times 10^6$ s, $1.0 \times 10^7$ s, $1.0 \times 10^8$ s respectively for $Q_D = 2.6 \times 10^4$ (a) and $Q_D = 2.6 \times 10^{-3}$ (b). (c) represents the evolution of the coulomb stress ratio under $Q_D = 2.6 \times 10^4$ and $Q_D = 2.6 \times 10^{-3}$ with isothermal or non-isothermal injection conditions.
The propagation of the thermal front within the rock is therefore likely an important factor in defining the timing and magnitude of seismicity. When the dimensionless flow rate $Q_D$ is smaller than $2.6 \times 10^{-2}$, the timing of seismicity is exclusively governed by the timing of the arrival of the thermal front at the fault (Figures 2-5-d, 2-5-e, and 2-5-f). In terms of the physical characteristics of the reservoir used here, these corresponding to real times of $t = 1.0 \times 10^7 s (\sim 100d)$, $3.1 \times 10^7 s (\sim 300d)$, and $6.5 \times 10^7 s (\sim 752d)$ for $Q_D = 2.6 \times 10^{-2}$, $2.6 \times 10^{-4}$, $2.6 \times 10^{-6}$ respectively. Conversely, for large $Q_D$, the cooling regime is spread more broadly across the reservoir and therefore may activate a larger patch at this changed stress. Thus, the arrival of the zone of high thermal gradient at the fault is the principal factor that controls the timing of thermally induced seismicity.

Moreover, the slip distance distributions for each patch along the fault reflect the magnitude of the seismic events (Figure 9(a)) that are associated with the different forms of the migrating thermal front. As the dimensionless injection rate $Q_D$ increases, the corresponding magnitude of seismicity event also grows. The magnitude of these individual events may be evaluated from the slip distribution as

$$M_0 = \int_0^L \mu LWdD_c$$

(16)

where $M_0$ is seismic moment, $L$ is the fault length, $W$ is the width of fault rupture, $\mu$ is the rigidity of fault (taken here as 1 GPa), and $D_c$ is the slip distance along the fault patch. This seismic moment may be converted into a moment magnitude $M_s$, used to measure the strength of the seismic event. The $M_s - M_0$ relationship is defined as [Kanamori and Abe, 1979; Purcaru and Berckhemer, 1982],

$$\log M_0 = 1.5M_s + 16.1$$

(17)
The reservoir thickness is 15 m used in the model. In order to obtain moment magnitudes that are appropriate to the 3-D representation of the fault (fault area of 442m × 442 m), we use the results from the 2-D plane strain model and extrapolate these over the fault area. This switch between the 2-D slip model and the 3-D fault ignores the clamped boundaries (zero displacement) at the top and base of the fault and would slightly overestimate the moment magnitude—relative to the real case where the edges of the fault are clamped.

Figure 9b indicates that the magnitudes of induced events increase progressively with an increase in the dimensionless flow rate. For small \( Q_D \) \((2.6 \times 10^{-6})\), the resulting event magnitude is 2.74 and this elevates to 2.86 as \( Q_D \) is increased \((2.6 \times 10^3)\).

![Graphs showing slip distance and seismicity magnitude with varying flow rates.](image)

Figure 2.9 (a) the comparison of slip distance distributions in different patches along the fault under the different dimensionless flow rate \( Q_D \), (b) the corresponding maximum magnitude of seismicity based on the slip distance results under different flow rate \( Q_D \).
The outcome that the largest circulation rates give the largest events appears to contradict the suggestion that the largest events will result from the most non-uniform thermal field – a thermal field that will occur for the lowest flow rates. A plausible mechanism for this observation is that the chilled area along the fault, which ultimately contributes to the destressing and then slips, correlates positively with $Q_D$. Thus the larger flow rates result in a larger cooled region on the fault and although the stress drops are smaller than for the abrupt thermal front, the resulting product of stress-drop and slipped area are larger. Figure 10(a) ($Q_D = 2.6 \times 10^{-8}$) shows that only a small portion of the fault is locally affected by the arrival of the thermal front for small non-dimensional flow rates ($t = 6.2 \times 10^7 s$). In comparison, for a larger $Q_D$ ($2.6 \times 10^3$; Figure 2-10(b)), the cumulative thermal stress initiates a larger fault reactivation at later time ($t = 5.0 \times 10^9 s$) since the entire fault is uniformly cooled. This explains the observations of Figure 9 where event magnitude grows with $Q_D$. Thus both the dimensionless timing of seismicity $t_d$ and the event magnitude $M_s$ both increase with an increase in the dimensionless flow rate as shown in Figure 2-9 and 2-10.
Figure 2-10 (a) The fault temperature evolution under $Q_D = 2.59 \times 10^{-3}$, the two dashed lines represent the area affected by the thermal stress acting on the fault when slip occurs at $6.2 \times 10^7$ s, (b) the fault temperature evolution under $Q_D = 2.59 \times 10^3$, the two dashed lines at the two tips of fault shows the fault regime affected by the thermal stress due to the cooling.

6 Output power optimization

Since the propagation of the thermal front at different dimensionless flow rates $Q_D$ influences both the form and distribution of thermal drawdown within the reservoir, the overall thermal output of the reservoir should scale with $Q_D$. Thus the rate of thermal energy production (power) may be determined scaled with this parameter, together with its longevity. These two observations, together give the cumulative energy output.
Thermal power output, $P_t$, may be defined as,

$$P_t = Q \Delta H$$  \hfill (18)

where $Q$ is the mass flow rate (kg/s), and $\Delta H$ is the enthalpy difference between the outlet water enthalpy and the enthalpy of injection water.

Figure 2-11 compares the evolution of power generation rate for various $Q_D$. The curves share an identical initial generation rate of $\sim30$ MW, but diverge after the transient production period $t = 1.0 \times 10^3 s$. The response for the two end-member magnitudes of $Q_D$ ($2.6 \times 10^{-6}$ and $2.6 \times 10^4$) represent the two most unfavorable production scenarios. At large flow rates ($Q_D > 2.6 \times 10^4$) the reservoir is unable to transfer heat to the massive flux of cold water after the initial removal of heat from the fracture skin. As a consequence the outlet drops precipitously after $t = 1.0 \times 10^7 s (\sim 115d)$. The converse is true at low flow rates ($Q_D = 2.6 \times 10^{-6}$) where the output is hot but the low mass flow rate limits power generation to $\sim15Mw$. The sweetspot with the most favorable conditions for power generation are in the range of $Q_D = 2.6 \times 10^{-2} \sim 2.6 \times 10^2$. The curve with $Q_D = 2.6 \times 10^{-2}$ yields the maximum cumulative power generation within 1 year, while the red curve with $Q_D = 2.6 \times 10^2$ results in larger potential of late stage power generation. It could be explained that the large volume of injection reduced the effective stress by elevating the pore pressure of reservoir at a large extent, the permeability around the production well could be further improved by the occurrence of fracture shearing. Therefore the mass flow rate at the outlet increased significantly. According to Figure 2-11, it is desirable to produce the geothermal reservoir with flow rates in the range $Q_D = 2.6 \times 10^{-2} \sim 2.6 \times 10^2$ to maximize energy recovery.
The results of power generation rate calculation under different \( Q_d \) values within 50 years injection, the magenta curve represents the smallest \( Q_d = 2.6 \times 10^6 \), and the green curve represents the largest \( Q_d \) value equal to \( 2.59 \times 10^4 \).

**7 Conclusions**

The foregoing defines the evolution of heat transfer in a fractured geothermal reservoir characterized by non-dimensional parameters. The evolution of water temperature and mean temperature in the rock is conditioned by dimensionless parameters representing the flow rate \( Q_d \) and time \( t_d \). The dimensionless flow rate \( Q_d \) is conditioned by the in-situ fracture spacing, prescribed mass injection rate and reservoir geometry and influences the thermal drawdown response of the reservoir. The sensitivity tests have explored the effect of, fracture spacing, fault permeability and injection temperature [Gan and Elsworth, 2014]. Based on this dimensionless model, this work captures the thermal drawdown response of the host hot rock at different
reservoir scales and for different spacing and permeabilities of fracture networks. More importantly, the timing and magnitude of thermally-driven fault seismicity are rigorously investigated under the various scenarios of thermal front propagation in rocks.

The primary control parameter $Q_D$ transforms dimensionless timing and temperature data into two bounding asymptotic behaviors. These two bounding asymptotic behaviors refer to the situations of heat transfer dominated by heat conduction where the drawdown gradients of dimensionless temperatures with time become asymptotically and infinitely steep (vertical) around $t_D/Q_D \sim 1$, when the $Q_D$ value decreases below $2.6 \times 10^{-4}$. When $Q_D$ reaches $2.6 \times 10^4$, the curves become asymptotic to a horizontal line anchored at $T_D \sim 1$. This represents the case where the velocity of fluid in the reservoir is sufficiently rapid that heat transfer from the rock to the fluid is conduction limited and small. This results in an early cold water breakthrough at the outlet and uniform thermal drawdown in the rock. The magnitude of $Q_D$ has an impact in determining the sequence of the parallel steep curves (dimensionless $t_D$). When the $Q_D$ value grows by one order of magnitude, the corresponding dimensionless timing $t_D$ for thermal depletion of water or rock is approximately elevated by one order magnitude for $Q_D < 5.2$. The situation with a lower magnitude $Q_D$ ($< 5.2$ in this model configuration) yields a uniform propagation of the thermal front, while the case with larger magnitude $Q_D$ ($> 2.6 \times 10^3$) produces a more uniform thermal distribution across the whole reservoir without a distinct thermal front.

Under the condition of propagation of a uniform thermal front, the timing for fault reactivation is determined as the thermal front arrives at the fault. The spatial thermal gradient adjacent to the front (and then arriving at the fault) is the principal factor defining the timing of triggered seismicity. As the dimensionless ratio $Q_D$ increases, accordingly the dimensionless timing for the onset of thermal-driven seismicity is also linearly increased. Similarly, the magnitude of fault slip
distance also grows with increments in $Q_D$, since the cooled area of fault area that exhibits thermal stress changes is proportionally increased with an increase in $Q_D$.

Finally, the $Q_D$ magnitude plays an important role in determining the rate of power generation and the ultimate heat extraction efficiency of the reservoir. It reveals that the optimum water production condition is located at an intermediate magnitude of $Q_D$ in the range of $2.6\times10^{-2} - 2.6\times10^{2}$. The two bounding magnitudes of $Q_D$ represent unfavorable conditions where flow rates are either too small or outlet temperatures too small to yield significant power.

Acknowledgement

This work is the result of partial support from the US Department of Energy under project DOE-DE-343 EE0002761. This support is gratefully acknowledged. The authors would like to thank the anonymous reviewers for their valuable comments and suggestions to improve the quality of the paper.

8 Reference


Chapter 3

A Continuum Model for Coupled Stress and Fluid Flow in Discrete Fracture Networks

Abstract

We present a model coupling stress and fluid flow in a discontinuous fractured mass represented as a continuum by coupling the continuum simulator TF_FLAC$^{3D}$ with cell-by-cell discontinuum laws for deformation and flow. Both equivalent medium crack stiffness and permeability tensor approaches are employed to characterize pre-existing discrete fractures. The advantage of this approach is that it allows the creation of fracture networks within the reservoir without any dependence on fracture geometry or gridding. The model is validated against thermal depletion around a single stressed fracture embedded within an infinite porous medium that cuts multiple grid blocks. Comparison of the evolution of aperture against the results from other simulators confirms the veracity of the incorporated constitutive model, accommodating stress-dependent aperture under different stress states, including normal closure, shear dilation, and for fracture walls out of contact under tensile loading. An induced thermal unloading effect is apparent under cold injection that yields a larger aperture and permeability than during conditions of isothermal injection. The model is applied to a discrete fracture network to follow the evolution of fracture permeability due to the influence of stress state (mean and deviatoric) and fracture orientation. Normal closure of the fracture system is the dominant mechanism where the mean stress is augmented at constant stress obliquity ratio of 0.65 – resulting in a reduction in permeability. Conversely, for varied stress obliquity (0.65 – 2) shear deformation is the principal mechanism resulting in an increase in permeability. Fractures aligned sub-parallel to the major principal
stress are near-critically stressed and have the greatest propensity to slip, dilate and increase permeability. Those normal to direction of the principal stress are compacted and reduce the permeability. These mechanisms increase the anisotropy of permeability in the rock mass. Furthermore, as the network becomes progressively more sparse, the loss of connectivity results in a reduction in permeability with zones of elevated pressure locked close to the injector – with the potential for elevated pressures and elevated levels of induced seismicity.

1. Introduction

Geothermal energy is a potentially viable form of renewable energy although the development of EGS as a ubiquitous source has considerable difficulties in developing an effective reservoir with sustained thermal output. One key solution in generating an effective reservoir is to stimulate using low-pressure hydraulic-shearing or elevated-pressure hydraulic-fracturing. In either case, the stimulation relies on changes in effective stresses driven by the effects of fluid pressures, thermal quenching and chemical effects, each with their characteristic times-scales. Thus incorporating the effects of coupled multi-physical processes (Thermal-Hydraulic-Mechanical-Chemical) exerts an important control on the outcome [Taron and Elsworth, 2010]. Therefore an improved understanding of coupled fluid flow and geomechanical process offers the potential to engineer permeability enhancement and its longevity – and thus develop such reservoirs at-will, regardless of the geological setting [Gan and Elsworth, 2014a; b]. This is a crucial goal in the development of EGS resources.

The constitutive relationships linking fluid flow and deformation are more complex when the subsurface fluids flow through geological discontinuities like faults, joints and fractures. To better represent the discontinuities in the simulation of fractured masses, past efforts have focused on discretizing individual fractures or averaging fracture properties into the effective properties of
each grid block [Goodman, 1968; Noorishad et al., 1982; Elsworth, 1986; Heuze et al, 1990; Kolditz and Clauser, 1998], and investigating the coupled hydraulic–mechanical–thermal influence within the deformable fractured medium [Rutqvist and Stephansson, 2003; Kohl, et al., 1995]. Currently available models for fracture simulations are primarily divided into equivalent continuum and discontinuum approaches. Discontinuum models include boundary element methods [Ghassemi and Zhang, 2006; McClure and Horne, 2013], and distinct element methods [Fu et al., 2013; Min and Jing, 2003; Pine and Cundall, 1985]. The discontinuum approach for fractured masses assumes that the rock is assembled from individual blocks delimited by fractures. The fractures can be represented by either explicit fracture elements along fractures, or by interfaces [Zhang and Sanderson, 1994]. Given that rocks and fractures are explicitly characterized, the discontinuum approach is able to investigate the small-scale behavior of fractured rock masses, which may be more realistic in replicating in-situ behavior. However, discontinuum models applied in large reservoir simulations and for long term predictions demand greater computational efficiency and time.

Conversely, the major assumption for the equivalent continuum approach is that the macroscopic behavior of fractured rock masses, and their constitutive relations, can be characterized by the laws of continuum mechanics. The equivalent continuum approach has the advantage of representing the fractured masses at large scale, with the potential to recover simulation results of long-term response. The behaviors of fractures are implicitly included in the equivalent constitutive model and via effective parameters for modulus and permeability. One central concept in developing equivalent continuum approaches is that of crack tensor theory [Oda, 1986]. This includes a set of governing equations for solving the coupled stress and fluid flow problem with geological discontinuities, which contains the fracture size, fracture orientation, fracture volume, and fracture aperture. The rock mass is treated as an equivalent anisotropic porous elastic medium with the corresponding elastic compliance and permeability tensors.
We adapt the continuum simulator TFREACT [Taron et al., 2009], which couples analysis of mass and energy transport in porous fractured media (TOUGH) and combines this with mechanical deformation (FLAC3D, [Itasca, 2005]) with extra constitutive models including permeability evolution and dual-porosity poroelastic response. The purpose in this work is to extend the analysis of fracture flow and fracture deformation to randomly and discretely fractured rocks, and to provide a tractable solution to optimize for fluid flow and thermal production in spatially large and complex fracture networks. To better represent the permeability evolution due to the influence of stress, the constitutive model for stress-dependent permeability evolution is extended to include the scenario of fractures opening in extension – specifically where large fractures traverse individual computational cells. For this, crack tensor theory is employed to determine the equivalent mechanical properties of the fractured rock mass in tensor form, differentiating the responses of the fluid flow and stress from both the intact rock and the fractured rock mass. The constitutive model for the evolution of stress-dependent permeability accommodates three different stress states, including normal closure, shear dilation, and the potential for fracture walls to lose contact under extensional loading. The accuracy of the simulator is assessed by validation against the interaction of fracture opening and sliding deformation in response to fluid injection inside a single long fracture embedded in a poroelastic medium. By assessing the simulation results against the results of other discontinuum simulators, the feasibility of the approach is confirmed in simulating the coupled thermal-hydro-mechanical behavior in discretely fractured rock masses. A series of parametric tests are conducted with different mean stress conditions and stress obliquity conditions and fracture network configurations. These provide insights into fluid transport and the evolution of fracture aperture characteristics and permeability including the evolution of permeability anisotropy and flow channeling.
2. Constitutive model development

To implement an equivalent continuum model accommodating the fractured mass, four constitutive relations require to be incorporated. These are the relations for a crack tensor, a permeability tensor, a model for porosity representing the fracture volume, and a model for stress-dependent fracture aperture.

2.1 Crack tensor

To represent the heterogeneous distribution of components of fractured rock in the simulation, the mechanical properties of fractures are characterized in tensor form based on the crack tensor theory proposed by Oda [Oda, 1986]. The theory is based on two basic assumptions: (1) individual cracks are characterized as tiny flaws in an elastic continuum; and (2) the cracks are represented as twin parallel fracture walls, connected by springs in both shear and normal deformation. By predefining the fracture properties, such as position, length, orientation, aperture, and stiffness, we implement crack tensor theory as a collection of disc-shaped fractures in a 3D system, and modify the distribution of modulus corresponding to the fractured rock and intact rock in each intersected element. Here the intact rock is assumed to be isotropic, the conventional elastic compliance tensor $M_{ijkl}$ for intact rock is formulated as a function of Poisson ratio, $\nu$, and the Young’s modulus of the intact rock, $E$, as

$$M_{ijkl} = \frac{(1+\nu)\delta_{ij}\delta_{kl} - \nu\delta_{ik}\delta_{jl}}{E}$$

The compliance tensor $C_{ijkl}$ for the fractures is defined as a function of fracture normal stiffness $K_{nf}$, fracture shear stiffness $K_{sf}$, fracture diameter $D$, and components of crack tensors $F_{ij}$, $F_{ijkl}$ respectively.
$$C_{ijkl} = \sum \left[ \left( \frac{1}{K_{nf}}D - \frac{1}{K_{nf}}D \right) F_{ijkl} + \frac{1}{4K_{nf}D} \left( \delta_{ik}F_{jl} + \delta_{jk}F_{il} + \delta_{il}F_{jk} + \delta_{jl}F_{ik} \right) \right]$$  \hspace{1cm} (2)

where \textit{fracnum} is the number of fractures truncated in an element block, \(\delta_{ik}\) is the Kronecker’s delta. The related basic components of crack tensor for each crack intersecting an element are defined \(F_{ij}\) as below [Rutqvist et al., 2013],

\[F_{ij} = \frac{1}{V} \pi \frac{D^3 n_i n_j}{4}\]  \hspace{1cm} (3)

\[F_{ijkl} = \frac{1}{V} \pi \frac{D^3 n_i n_j n_k n_l}{4}\]  \hspace{1cm} (4)

\[P_{ij} = \frac{1}{V} \pi \frac{D^2 b^3 n_i n_j}{4}\]  \hspace{1cm} (5)

where \(F_{ij}, F_{ijkl}, P_{ij}\) are the basic crack tensors, \(b\) is the aperture of the crack, \(V\) is the element volume and \(n\) is the unit normal to each fracture. Therefore the formula for the total elastic compliance tensor \(T_{ijkl}\) of the fractured rock can be expressed as,

\[T_{ijkl} = C_{ijkl} + M_{ijkl}\]  \hspace{1cm} (6)

Combining equation 3-5 into equation 2, the equivalent fracture Young’s modulus \(E^f\) and Poisson ratio \(\nu^f\) can be obtained as,

\[E^f = \frac{1}{E + \left( \frac{1}{K_{nf}} - \frac{1}{K_{nf}} \right) \frac{1}{V} \frac{\pi D^3 n_i^4}{4} + \frac{1}{K_{nf}} \frac{1}{V} \frac{\pi D^3 n_i^4}{4}}\]  \hspace{1cm} (7)

\[\nu^f = \frac{\nu}{E} E^f - \left( \frac{1}{K_{nf}} - \frac{1}{K_{nf}} \right) \frac{E^f}{V} \frac{\pi D^2 n_i^2 n_j^2}{4}\]  \hspace{1cm} (8)

Given the assumption that the properties of modulus are anisotropic, the equivalent bulk modulus \(K\) and shear modulus \(G\) for the fractured rock mass are formulated as below,
where $K_{\text{int,act}}$ is the bulk modulus of the intact rock, $G_{\text{int,act}}$ is the shear modulus of the intact rock and $V_{\text{ratio}}$ is the volumetric ratio of the truncated fracture over the element volume. The stress-dependent evolution of fracture aperture will in turn update the equivalent modulus of the fractured rock masses.

### 2.2 Permeability tensor and aperture evolution

Considering that the randomly distributed fractures may be intersected by multiple elements in the reservoir gridding, the directional fracture permeability is defined as a permeability tensor $k_{ij}$, which is able to represent the orientation of fractures and the explicit fracture volume intersecting any element block.

$$k_{ij} = \frac{1}{12} \sum_{i} \left( P_{ik} S_{k} - P_{ij} \right) = \frac{1}{12} \sum_{i} \left( \frac{V_{\text{ratio}} b_{in} b_{nj}^{3} n_{k}^{2} S_{ij} - b_{i}^{3} n_{i}^{3} n_{j}}{b_{in}} \right)$$

where $b_{in}$ is the initial aperture of the fracture.

The effect of stress has a direct impact in changing the evolution of the fracture aperture, which will in turn change the compliance tensor in the simulation loop. Prior models for stress permeability coupling include hyperbolic models of aperture evolution [Bandis et al., 1983; Barton and Choubey, 1977], which can describe the response of fracture aperture in normal closure under the influence of in-situ stress. The functionality of the hyperbolic model is
mediated by the parameters of initial fracture normal stiffness \( K_{nf}^0 \), maximum closure of the fracture aperture \( d_{n\text{max}} \), initial aperture of the fracture, \( b_{ini} \), and the effective normal stress of the fracture \( \sigma'_n \), which is formulated as,

\[
\Delta d_n = \frac{d_{n\text{max}}}{1 + \frac{K_{nf}^0 d_{n\text{max}}}{\sigma_n}}
\]

A simplified Barton-Bandis hyperbolic model [Baghbanan and Jing, 2007] is adopted to model aperture evolution by introducing a new parameter – the critical normal stress \( \sigma_{nc} \), which means that the normal compliance \( C_n \) is reduced significantly when the aperture closure approaches the maximum closure. In order to simplify the hyperbolic solution it is assumed that the ratio of maximum normal closure \( d_{n\text{max}} \) relative to initial fracture aperture \( b_{ini} \) is constant at 0.9. Given this assumption, the hyperbolic normal closure equation is transformed as,

\[
\sigma'_n = \frac{\sigma_{nc} \Delta d_n}{10(0.9 b_{ini} - \Delta d_n)}
\]

and the normal stiffness is determined by the normal stress as,

\[
K_{nf} = \frac{(10\sigma'_n + \sigma_{nc})^2}{9\sigma_{nc} b_{ini}}
\]

where \( \sigma_{nc} (\text{MPa}) = 0.487 b_{ini} (\mu\text{m}) + 2.51 \). Figure 3-1 shows the hyperbolic relationship between the normal stress and the aperture corresponding to different predefined apertures. This shows that the larger the initial aperture, the larger drawdown gradient of normal stress.
Fracture shear slip and related dilation are included in the simulator by lumping the influence into the response of the matrix rock being sheared. When the Coulomb failure criterion is reached, the shear displacement $u_s$ will generate shear dilation $b_{ds}$ in the normal direction according to the equation (Figure 3-2),

$$b_{ds} = u_s \tan \phi_d$$

where $\phi_d$ is the dilation angle. Figure 3-2 identifies the relationship between the shear stress and displacement due to normal dilation. When the shear stress reaches the critical magnitude $\tau_{sc}$, which is determined by the Coulomb failure criterion, shear failure triggers normal dilation (red line) to increase the fracture aperture as the shear displacement increases. To incorporate the weakening response for the onset of shear failure in fractured rock masses, the reduction of a
linear slope gradient (black line) represents the significant reduction of fracture shear stiffness from $K_{s1}$ to $K_{s2}$ due to shear failure. The magnitude of the aperture increment added by shear dilation can be calculated as,

$$b_{dila} = \frac{\tau - \tau_{sc}}{K_s} \tan \phi_d$$

Figure 3-2 Fracture normal dilation displacement evolution induced from the shear slip in fracture.

When the fluid pressure in the fracture exceeds the normal stress across the fracture, the two walls of the fracture are separated and the effective normal stress is zero [Crouch and Starfield, 1991] since $P_f = \sigma_n$. 
Figure 3 represents the constitutive relation for fracture aperture evolution applied in this model. The curve to the right is the regime under normal closure and shear dilation. However, as soon as the fluid pressure reaches the critical magnitude $P_{f0}$ where effective stress is zero (left side in Figure 3), a geometrical stiffness $K_{gf}$ for a penny-shaped fracture is employed to calculate the induced normal opening displacement when the two walls are under tension. The normal opening displacement is linear with an increment of fluid pressure ($P_f - P_{f0}$). This geometrical stiffness $K_{i,\text{rock}}$ [Dieterich, 1992], although small, is much larger than that of the fracture in shear and is defined as,

$$K_{i,\text{rock}} = \eta \frac{2G}{D} = \frac{7\pi G}{12 D}$$

where $G$ is the shear modulus of the intact rock, $D$ is the fracture half length, and $\eta$ is a geometrical factor which depends on the crack geometry and assumptions related to slip on the
patch [Dieterich, 1992]. In this study, $\eta$ is defined to represent a circular crack and is given as $\frac{7\pi}{24}$. Therefore the equation for the fracture opening displacement $b_{\text{open}}$ is formulated as below,

$$b_{\text{open}} = \frac{P_f - P_0}{K_{gf}} = \frac{P_f - P_{f0}}{10K_{\text{rock}}} = \frac{(P_f - P_{f0})}{10 \times \frac{7\pi G}{12 D}}$$

To summarize, equations 11, 15, and 17, represent the relations for considering stress-dependent aperture change including normal closure, shear dilation, and fracture opening is obtained as,

$$b = b_{\text{ini}} - \frac{9b_{\text{ini}} \sigma_n}{\sigma_{nc} + 10\sigma_n} + \frac{\tau - \tau_{sc}}{K_i} \tan \phi_d + \frac{(P_f - P_{f0})}{10 \times \frac{7\pi G}{24 r}}$$

where $b_{\text{ini}}$ is the initial aperture of the fracture, $b_{\text{normal}}$ is the reduction of aperture due to the normal closure, $\sigma_n$ is the effective normal stress of the fracture, $\sigma_{nc}$ is the critical normal stress, $\tau_{sc}$ is the critical shear stress where shear failure happens.

### 2.3 Porosity model

Considering that deformations occur independently within the two different media of fracture and matrix, it is important to accommodate the evolution of the dual porosity system with the induced strain, since the porosity is iteratively coupled in the hydro-mechanical simulations. Hence in this study, there are two different equations to represent the evolution of porosity in fracture and matrix.
matrix. In terms of the matrix, the volumetric strain is employed to update the matrix porosity as [Chin et al., 2000],

\[ \phi_{m}^{n+1} = 1 - (1 - \phi_{m}^{n}) e^{-\Delta \varepsilon_v} \]

where \( \Delta \varepsilon_v \) is the change in matrix volumetric strain, \( \phi_{m}^{n+1} \) and \( \phi_{m}^{n} \) are the matrix porosity at time \( t_{n+1} \) and \( t_{n} \), respectively. The fracture porosity is calculated as below,

\[ \Delta \varepsilon_f = \frac{\Delta b}{b_{ini}} \]

\[ \phi_{f}^{n+1} = 1 - (1 - \phi_{f}^{n}) e^{-\Delta \varepsilon_f} \]

where \( \Delta b \) is the aperture change, \( \Delta \varepsilon_f \) is the change of fracture volumetric strain. The assumption is made that only the aperture evolution \( \Delta b \) in the normal direction is considered in calculating the fracture volumetric strain \( \Delta \varepsilon_f \).

### 2.4 Numerical simulation workflow

Based on the constitutive model described above, the workflow for the equivalent continuum model is presented in Figure 3-4. The simulation initiates with the equilibration of temperature \( (T) \) and pore pressure \( (P_f) \) in TOUGH. Subsequently, initial data describing the fracture network, including fracture orientation, trace length, aperture, and modulus are input into a FORTRAN executable. The compliance tensor transfers the composite fracture modulus with the equilibrium pore pressure distribution into FLAC3D to perform the stress-strain simulation. The revised undrained pore pressure field is then redistributed, based on principles of dual porosity poromechanics, and applied to both fracture and matrix. The stress-dependent fracture aperture is
calculated and updated based upon the failure state of the fracture. Since the fracture permeability and composite modulus of the fractured medium are both mediated by the magnitude of fracture aperture, the fracture aperture is iteratively adjusted in the simulation loop to define the revised fracture permeability and to alter the compliance tensor of the composite fractured mass.

![Diagram](image)

Figure 3-4 Equivalent continuum simulation workflow implementation in TF_FLAC^3D.

3. Model verification

In this section, the discrete fracture network (DFN) model is verified by comparing the results against other discrete fracture network models. The model in this study [Kelkar et al., 2015] is an injection well intersecting a single fracture that dilates and slips in response to fluid injection.
3.1 Model setup

Figure 3-5 shows the reservoir geometry applied in this study. The single fracture is oriented at 45 degrees to the principal stresses and embedded within an infinite medium. The fracture has a length of 39 m with an initial width of 1 mm and does not propagate. The injection well is centrally located along the fracture with constant injection at $6.0 \times 10^{-8} m^3/s$. The maximum principal stress is 20 MPa (y-direction) and the minimum principal stress is 13 MPa (x-direction). Initial pore pressure and reservoir temperature are each uniform at 10 MPa and 420 K. The initial reservoir properties used in this model are listed in Table 1. The pre-stressed fracture is in equilibrium with the prescribed stress and pore pressure to yield the desired initial aperture of 1 mm.
Figure 3-6 Fracture aperture evolution comparisons against other discontinuum models.
Table 3-1 Data used in the simulation [McTigue, 1990].

<table>
<thead>
<tr>
<th>Parameter (unit)</th>
<th>Magnitude</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shear modulus, G (GPa)</td>
<td>15</td>
</tr>
<tr>
<td>Poisson’s ratio, $\nu$</td>
<td>0.25</td>
</tr>
<tr>
<td>Undrained Poisson’s ratio</td>
<td>0.33</td>
</tr>
<tr>
<td>Matrix permeability, $k_m, (m^2)$</td>
<td>$4.0 \times 10^{-19}$</td>
</tr>
<tr>
<td>Matrix porosity, $\phi_m$</td>
<td>0.01</td>
</tr>
<tr>
<td>Biot’s coefficient, $\alpha$</td>
<td>0.44</td>
</tr>
<tr>
<td>Water viscosity, $\mu$, (Pa.s)</td>
<td>$3.547 \times 10^{-4}$</td>
</tr>
<tr>
<td>Fluid compressibility, (MPa$^{-1}$)</td>
<td>$4.2 \times 10^{-4}$</td>
</tr>
<tr>
<td>Thermal expansion coefficient of solid, $\alpha_s (K^{-1})$</td>
<td>$2.4 \times 10^{-5}$</td>
</tr>
<tr>
<td>Thermal diffusivity of intact porous rock, $c_T (m^2 / s)$</td>
<td>$1.1 \times 10^{-6}$</td>
</tr>
<tr>
<td>Fluid density, $\rho_w (Kg / m^3)$</td>
<td>1000</td>
</tr>
<tr>
<td>Heat capacity of fluid, $c_w (Jkg^{-1}K^{-1})$</td>
<td>4200</td>
</tr>
<tr>
<td>Initial reservoir temperature (K)</td>
<td>420</td>
</tr>
<tr>
<td>Injection water temperature (K)</td>
<td>400</td>
</tr>
<tr>
<td>Initial joint normal stiffness, $k_n (GPa/m)$</td>
<td>0.5</td>
</tr>
<tr>
<td>Initial joint shear stiffness, $k_s (GPa/m)$</td>
<td>50</td>
</tr>
<tr>
<td>Fracture aperture initial, $b_m$ (mm)</td>
<td>1</td>
</tr>
<tr>
<td>In-situ stress (MPa) – y direction</td>
<td>20</td>
</tr>
<tr>
<td>In-situ stress (MPa) – x direction</td>
<td>13</td>
</tr>
<tr>
<td>Initial reservoir pore pressure (MPa)</td>
<td>10</td>
</tr>
<tr>
<td>Injection rate ($m^3 / s$) /m thickness of reservoir</td>
<td>$6.0 \times 10^{-8}$</td>
</tr>
<tr>
<td>Friction angle, dilation angle</td>
<td>$30^\circ, 2.5^\circ$</td>
</tr>
<tr>
<td>Fracture cohesion, $C, MPa$</td>
<td>0</td>
</tr>
</tbody>
</table>
3.2 Results discussion

In this section, the results are compared between the contrasting conditions of isothermal injection and non-isothermal injection. To isolate the impact of the induced thermal stress effect in the aperture evolution, the liquid viscosity is set as constant for both the isothermal and non-isothermal injection conditions.

Figure 3-6 presents the results of fracture aperture evolution under isothermal injection conditions for the first 180 days. By comparing the results from our equivalent continuum approach against other those for discrete fracture models, including GeoFrac [Ghassemi and Zhang, 2006] and CFRAC [McClure and Horne, 2013] we verify that the equivalent continuum model TF_FLAC3D is able to match results for the evolution of fracture aperture.

Figure 3-7 presents the evolution of injection pressure in the fracture among the three different simulators for the condition of isothermal injection. There is a good agreement between the injection pressures recovered from TF_FLAC3D and the other discrete fracture models. In this response, the normal aperture grows slowly under initial pressurization and most rapidly as the walls lose contact and the full geometric stiffness of the fracture is mobilized as the fracture walls lose contact. The walls of the fracture are out of contact after ~60 days of injection. Due to permeability enhancement in the fracture, the injection pressure gradient in the fracture decreases after the fracture opens.

Figure 3-8 presents a comparison of injection pressures between isothermal and non-isothermal injection. In this, water is injected at 400 K for a system originally in thermal equilibrium at 420 K. The injection pressure results for these two conditions are similar. However, there is a notable difference in the growth in fracture aperture between the two injection scenarios (Figure 3-9). The major difference occurs when the fracture walls lose contact. Prior to fracture separation, the fracture aperture for non-isothermal injection is slightly larger than that for isothermal injection.
This can be explained by following the evolution of the normal stress acting across the fracture, as noted in Figure 3-10 – and is a consequence of thermal unloading by the quenching fluid. The thermal unloading effect is more pronounced when the fracture is in extension (open).

![Graph showing evolution of fracture injection pressures evaluated by various models.](image)

Figure 3-7 Evolution of fracture injection pressures evaluated by various models.

Figure 11 shows the distribution of aperture along the fracture at 72 days and 180 days for both the isothermal injection and non-isothermal injection cases. There is no significant difference in the distribution of fracture aperture for isothermal and non-isothermal cases at 72 days, although the results diverge by 180 days. By 180 days, the influence of the quenching fluid in reducing the fracture-local normal stress has become sufficiently significant to increase the aperture by ~3% for a permeability increase of the order of $1.03^{3}\sim 10\%$. 
Figure 3-8 Evolution of injection pressure for isothermal injection (black line) and non-isothermal injection (red line).

Figure 3-9 Evolution of fracture normal aperture for isothermal injection (black line) and non-isothermal injection (red line), respectively.
Figure 3-10 Evolution of fracture normal stress under isothermal injection (black line) and non-isothermal injection (red line).

Figure 3-11 Aperture distribution along the fracture at 72 days and 180 days under conditions of both isothermal injection and non-isothermal injection.
3.3 Multi-fracture validation

The previous TFREACT simulator is able to simulate the response of fracture aperture and pore-elasticity in the framework of orthogonal fracture sets. In this section, the simulation of multi-fracture intersection was completed between the equivalent continuum model TF_FLAC\(^\text{3D}\) and the original TFREACT (Figure 3-13), which aims at validating the correctness of the developed equivalent continuum model in simulating the interaction of multi-fractures. In Figure 3-12, there are two sets of orthogonal fractures (red and green lines) ubiquitously distributed in a 200m × 200m × 10m reservoir. The fractures are separated at a constant spacing 4m. The injector is centrally located in the reservoir with a constant injection rate of 0.01 m\(^3\)/s. The reservoir properties are described in Table 1.

In the model of continuum TFREACT, the evolution of fracture permeability is represented by a hyperbolic function as,

\[
b = b_r + (b_m - b_r) \times \exp(\sigma_N \times a)
\]

Where \(b_r\) is the residual aperture, \(b_m\) is the maximum aperture, \(\sigma_N\) is the effective normal stress of the fracture (MPa), \(a\) is the non-linear fracture stiffness (1/MPa), which is defined as 1.4 MPa\(^{\text{1}}\) in this model. Figure 3-13 shows the evolution of fracture aperture over time. There is good agreement in the magnitude of fracture aperture between the continuum TFREACT and the equivalent continuum TF_FLAC\(^\text{3D}\). The injection pressure results are either validated in Figure 3-14. When the fracture pressure increases, the decreased effective normal stress prompts the enhancement of fracture aperture.
Figure 3-12 Schematic of two sets of orthogonal fracture ubiquitously distributed in a 200m × 200m × 10m reservoir.
Figure 3-13 Validation of fracture aperture at the injection well between the developed equivalent continuum TF FLAC$^{3D}$ and the original continuum TFREACT [Taron et al., 2009].

Figure 3-14 Validation of injection pressure between the developed equivalent continuum TF FLAC$^{3D}$ and the original continuum TFREACT.
4. DFN application

In realistic reservoir, fractures networks usually are non-uniformly distributed. Complex fracture pattern yields heterogeneous fluid flow and heat thermal drawdown [Bear, 1993; Tsang and Neretnieks, 1998], and the development of anisotropic fracture permeability, which could induce flow channeling in the major fractures [Chen et al., 1999; Min et al., 2004]. In this section, a reservoir model with two discrete fracture networks sets is constructed to address the evolution of fracture permeability, due to the influence of stress state and fracture orientation.

4.1 Fracture network generation

To create the discrete fracture network in the simulation, various factors including fracture location, orientation, length, and aperture are necessarily considered. In this work, the two fracture networks are oriented at azimuths (from the North) of 020 degrees and 135 degrees in a 200m × 200m × 10m reservoir (Figure 3-15c). The injector is located at coordinate (20,140). The geometry of each individual fracture is defined by prescribing the starting and ending point according to the fracture length and orientation (Figure 3-15a). Each set of fractures comprises 50 individual fractures of various lengths distributed within the reservoir. There are several major fractures which allow the fluid to diffuse into the majority of reservoir. The length of fractures in the reservoir follows the traditional lognormal distribution (Figure 3-15b) [de Dreuzy et al., 2001; Muralidharan et al.]. The fracture length is constrained in the range of 1m to 60m. The initial aperture for each fracture is determined by a power law function (equation 22) [Olson, 2003], which implies that longer fractures of trace length \( l \) have greater initial aperture \( b_i \).

\[
b_i = 1.25 \times 10^{-5} \times l^{0.8}
\]
Figure 3-16 indicates that the initial fracture aperture in this model varies from $5.0 \times 10^{-3} \ m$ to $2.5 \times 10^{-4} \ m$, corresponding to the predefined range of fracture length.

The reservoir properties in the DFN model are the same and are defined in Table 3-1. In the base case, the maximum principal stress is 20 MPa (N-S direction) and the minimum principal stress is 13 MPa (E-W direction). The initial reservoir pressure is uniform at 10 MPa. The water is injected at a constant rate of $5.0 \times 10^{-6} \ m^3 / s$.

Figure 3-17(a) shows the resulting fracture pressure distribution at 180 days for the base case. The fracture permeability distribution in Figure 3-17(b) corresponds to the shear stress drop along both fracture sets in Figure 3-17(c) and 3-17(d). The shear stress around the injector drops ~3 MPa for the fracture set oriented at 045 degrees. Furthermore, the path of shear stress drop also follows with the path of major fractures, which increases the permeability of fractures.
Figure 3-15 (a) Locations of starting points and ending points for the two sets of fractures in the reservoir, (b) lognormal probability distribution for the length of fractures, (c) distribution of fracture networks in a 200 m × 200 m × 10 m reservoir, fractures in red are oriented at 135 degrees, and those in green are oriented at 020 degrees (with respect to the North).
Figure 3-16 Power law relationships between the fracture length and initial fracture aperture.
Figure 3-17 (a) Fracture pressure distribution for the base case at 180 days, (b) contour of fracture mean permeability, (c) shear stress drop along the first fracture set, (d) shear stress drop along the second set of fractures.

4.2 Effect of applied stress

Applied boundary stress has a direct impact in determining the potential of fracture shear failure and the resulting permeability evolution. Therefore it is desirable to investigate the various ratios of boundary stress conditions influencing the evolution of fracture permeability. To evaluate the effect of stress state, two scenarios of the ratio of boundary stresses are proposed. Table 3-2 illustrates the composition of the sensitivity tests for these applied boundary stresses. The initial reservoir pressure and injection rate are kept constant for all the cases.
Table 3-2 Sensitivity tests of applied stress boundaries in the fracture aperture evolution.

<table>
<thead>
<tr>
<th>Test category</th>
<th>$\sigma_x$, MPa</th>
<th>$\sigma_y$, MPa</th>
<th>$\sigma_x / \sigma_y$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stress ratio</td>
<td>13</td>
<td>20</td>
<td>0.65</td>
</tr>
<tr>
<td></td>
<td>19.5</td>
<td>30</td>
<td>0.65</td>
</tr>
<tr>
<td></td>
<td>26</td>
<td>40</td>
<td>0.65</td>
</tr>
<tr>
<td></td>
<td>39</td>
<td>60</td>
<td>0.65</td>
</tr>
<tr>
<td>Stress difference</td>
<td>20</td>
<td>20</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>30</td>
<td>20</td>
<td>1.5</td>
</tr>
<tr>
<td></td>
<td>40</td>
<td>20</td>
<td>2</td>
</tr>
</tbody>
</table>

The first test category in Table 3-2 indicates the schedule for the constant stress ratio. The applied boundary stresses are increasing proportionally, such that the stress ratio of $\sigma_x / \sigma_y$ is kept constant at 0.65. Figure 3-18 shows the fracture aperture distribution at 180 days for the two sets of fractures with increasing stress $\sigma_x$ from 13 MPa to 40 MPa. When the applied stresses are proportionally increasing, the initial apertures for the both fracture sets decrease uniformly, the response of normal closure is the dominant behavior by decreasing the initial aperture, resulting from the increased fracture normal stress.

Figure 3-19 illustrates the evolution of fracture permeability close to injector under the fixed stress ratio. As the applied boundary stresses are augmenting proportionally, the failure potential declines. Fracture closure is the dominating response due to the increased normal stress, resulting in reduction of fracture permeability.

Conversely, the deviatoric stress is elevated in the second set of cases by increasing the boundary stress $\sigma_x$, while holding the applied boundary stress $\sigma_y$ constant at 20 MPa. In Figure 3-20, the fracture permeability close to the injection well was selected to illustrate the development of permeability anisotropy when the stress difference is increasing. When the boundary stress $\sigma_x$ is increasing from 13 MPa to 40 MPa, the anisotropy of fracture permeability emerges. Figure 3-21
points out the fracture aperture evolutions for the two sets of fractures with an increasing deviatoric stress. As the applied boundary stress in the major principal stress direction (E-W direction) increases, the fractures normal to the major principal stress direction (fracture set 2) close, while the fractures aligned sub-parallel to the major principal stress (fracture set 1) are nearly critically stressed and have the greatest propensity to slip, dilate. Therefore the apertures in set 1 fractures are larger than those in set 2 fractures.
Figure 3-18 Fracture aperture distributions for the two sets of fractures under constant stress ratio at 180 days respectively.
Figure 3-19: Evolutions of fracture permeability around the injector under the fixed stress ratio within 180 days.

Figure 3-20: Evolution of fracture permeability ratio $k_x$ over $k_y$ under different stress difference.
Figure 3-21 Evolution of fracture aperture for the two sets of fracture with increasing stress difference. Normal closure is the dominating response as deviatoric stress increased. Fracture aperture in set 1 is larger than the set 2.

4.3 Effect of fracture orientation

Fracture orientation plays an important role in determining the stress state around the fracture, which will influence the potential of fracture failure and permeability enhancement. In this study, the impact of fracture orientation is assessed by comparing the evolution of fracture permeability between the critically-stressed and non-critically stressed situations. Figure 3-22 shows the designated fracture network geometries striking at azimuths of 020-135 degrees (Figure 3-22a), 060-120 degrees (Figure 3-22b), and 015-165 degrees (Figure 3-22c) (with respect to the North direction). The trace length for each fracture in the three cases is maintained the same magnitude, but at different azimuths. The network is not well connected when the set of fractures are oriented sub-parallel to the N-S direction (Figure 3-22c). Figure 3-23 shows the distributions of fracture
aperture at 180 days for different fracture orientations. Since the major principal stress is imposed in the N-S direction, the acting normal stress on the fractures aligned sub-parallel to the N-S direction (Figure 3-23c) is smaller than the fractures oriented normal to the N-S direction (Figure 3-23b), therefore it can be seen that the fracture aperture around the injector with 015-165 degrees (Figure 3-23c) are larger than the aperture in the case with 060-120 degrees (Figure 3-23b). However, since the fractures are not well connected in the third case with 015-165 degrees orientation, the permeability enhancement is only focused around the injector zone, the fracture pressure build-up is high enough to trigger the local shear failure around the injection well.

Figure 3-22 Contour of fracture networks under different orientations representing the fractures oriented at 020-135 degrees, 060-120 degrees, and 015-165 degrees with respect to the North separately.
Figure 3-23 Fracture aperture comparisons at 180 days between different fracture orientations at 020-135 degrees, 060-120 degrees, and 015-165 degrees with respect to North.
5. Conclusion

This work presents the development of an equivalent continuum model to represent randomly distributed fractured masses, and investigating the evolution of stress-dependent permeability of fractured rock masses. The model incorporates both mechanical crack tensor and permeability tensor approaches to characterize the pre-existing fractures, accommodating the orientation and trace length of fractures. Compared to other discrete fracture models, the advantages of this model are primarily represented in simulating the large scale reservoir including the long term coupled thermal-hydraulic-mechanical response, and also without any dependence in the fracture geometry and gridding. The accuracy of simulator has been evaluated against other discrete fracture models by examining the evolution of fracture aperture and injection pressure during injection. The simulator is shown capable of predicting the evolution of the fracture normal aperture, including the state of fracture normal closure, shear dilation, and out of contact displacements under tensile loading.

The influence of stress state (mean and deviatoric) and fracture orientation on the evolution of fracture permeability are assessed by applying the model to a discrete fracture network. Normal closure of the fracture system is the dominant mechanism in reducing fracture permeability, where the mean stress is augmented at a constant stress obliquity ratio of 0.65. Conversely, for varied stress obliquity (0.65 – 2) shear deformation is the principal mechanism resulting in an increase in permeability. Fractures aligned sub-parallel to the major principal stress are near critically-stressed and have the greatest propensity to slip, dilate and increase permeability. Those fractures normal to direction of the principal stress are subjected to the increasing normal stress, and reduce the permeability. These mechanisms increase the anisotropy of permeability in the rock mass. Furthermore, as the network becomes progressively more sparse, the loss of
connectivity results in a reduction in permeability with zones of elevated pressure locked close to the injector – with the potential for elevated levels of induced seismicity.

Acknowledgement

This work is a partial result of support from the US Department of Energy under project DOE-DE-343 EE0002761. This support is gratefully acknowledged.

Reference


Chapter 4

Production Optimization in Fractured Geothermal Reservoir by Coupled Discrete Fracture Network Modeling

Abstract

In this work, a stimulation then heat production optimization strategy is presented for prototypical EGS geothermal reservoirs by comparing conventional stimulation-then-production scenarios against revised stimulation schedules. A generic reservoir is selected with an initial permeability in the range of $10^{-17}$ to $10^{-16}$ m$^2$, fracture density of ~0.09 m$^{-1}$ and fractures oriented such that either none, one, or both sets of fractures are critically stressed. For a given reservoir with a pre-existing fracture network, two parallel manifolds are stimulated that are analogous to horizontal wells that allow a uniform sweep of fluids between the zones. The enhanced connectivity that develops between the injection zone and the production zone significantly enhances the heat sweep efficiency, while simultaneously increasing the fluid flux rate at the production well. For a 10m deep section of reservoir the resulting electric power production reaches a maximum of 14.5 MWe and is maintained over 10 years yielding cumulative energy recoveries that are a factor of 1.9 higher than for standard stimulation. Sensitivity analyses for varied fracture orientations and stimulation directions reveal that the direction of such manifolds used in the stimulation should be aligned closely with the orientation of the major principal stress, in order to create the maximum connectivity. When the fractures are less prone to fail, the output electric power is reduced by a decrease in the fluid flux rate to the production well. The short circuiting response during heat extraction is significant for the low fracture density condition, which can result early thermal breakthrough in the production well.
1. **Introduction**

Enhanced geothermal reservoirs (EGS) have been shown to be a viable resource for the recovery of thermal energy. However, due to their intrinsic characteristic of low permeability and porosity they have proved intractable in developing sufficient fluid throughput by stimulation. The principal challenge has been in developing adequate permeability in the reservoir that also retains sufficient heat transfer area [Tester et al., 2006].

Numerical simulation is a reliable approach to investigate coupled multi-physics processes (Thermal-Hydraulic-Mechanical) and to better understand the fundamental mechanisms and feedbacks that occur in geothermal reservoirs. This is particularly important due to the intense pressure-sensitivity of fractures in the coupling of permeability and heat transfer area [Taron and Elsworth, 2009]. From previous studies, thermal quenching and resulting contractile strains may substantially unload the reservoir and increase both fracture aperture and permeability via creep or by induced seismicity and fault reactivation [Gan and Elsworth, 2014a; b; Segall and Fitzgerald, 1998]. This may occur close-in to the wellbore at early times and at later times in the far-field when larger features and faults may be affected [Elsworth et al., 2010; Taron and Elsworth, 2010a]. For discretely fractured rock masses, there are two major approaches to simulate the influence of randomly distributed fractures. One approach is as an equivalent continuum [Taron and Elsworth, 2010b] where the aggregate response is represented and an alternative is a discontinuum approach [Ghassemi and Zhang, 2006; McClure and Horne, 2013; Min and Jing, 2003; Pine and Cundall, 1985] where individual fractures are discretized and their individual response followed. Continuum methods have the advantage of effectively simulating behavior at large (field) scale and for the long-term due to the lower computational requirements. The behavior of fractures is implicitly included in the equivalent constitutive models for both deformation and transport. The central effort in developing the equivalent continuum approach is
the incorporation of crack tensor theory [Oda, 1986]. This is different in behavior from the application of discrete fracture network models (DFNs) where the behavior of individual fractures is explicitly represented in the macroscopic response. In previous work [Gan and Elsworth, 2015], an equivalent continuum T-H-M coupled simulator TF_FLAC3D has been developed to investigate the evolution of stress-dependent fracture permeability in equivalent DFNs. The benefits of this continuum simulator are in mechanically representing the fractured mass by adopting a crack tensor, but also in simulating the heat and mass transport by advection and in the long term, albeit for continuum problems.

Strategies for optimizing production (high flowrate, high temperature and long duration) in geothermal reservoirs have been explored [Marcou, 1985; Akin et al., 2010; Pham, 2010] by identifying the impact of various parameters on thermal extraction, and in proposing strategies to enhance thermal power generation. The rate of heat energy production is defined by the effluent water temperature and flow rate from the production well. The ideal condition is to maintain both a high flux rate and high temperature for as long as possible, while simultaneously delaying thermal breakthrough to the production well. The reservoir volume (and temperature) is the key parameter that determines the cumulative magnitude of energy production over the entire reservoir life [Sanyal et al., 2005]. This reservoir volume is in turn influenced by the well separation distance as the reservoir volume scales with the cube of this separation for a typical doublet injection-recovery system [Vörös et al., 2007]. In addition to reservoir volume and geometry, the characteristics of the injected fluid also exert some influence. Water density changes little in non-boiling systems but water viscosity may change by a factor of two or three with a change in temperature of 100-200 C and may therefore exert a direct impact on thermal production [Watanabe et al., 2000]. In addition to the ultimate recovery of thermal energy from the system, the rate of recovery is also important.
Dimensionless solutions are useful in defining the rate limiting processes and dependent properties for energy recovery. These simplified models capture the essence of the conductive heat supply to the convecting heat transfer fluid and define this process as the rate limiting step [Elsworth, 1989; 1990; Gringarten and Witherspoon, 1973; Gringarten et al., 1975; Pruess and Wu, 1993; Shaik et al., 2011]. The dimensionless parameter controlling the effectiveness of thermal recovery scales with the product of mass flow rate and fracture spacing to the second power [Gan and Elsworth, 2014] thus defining the principal desire for small spacing between fractures in draining the heat from the fracture-bounded matrix blocks.

This principal objective to circulate fluids at low rate per unit volume of the reservoir but to access small spacing between fractures is the principal requirement of a successful EGS system. However, fracture spacing, if activating and accessing pre-existing fracture networks is not a controllable parameter. The one controlling measure in production is to establish a uniform fluid-, and thereby thermal-sweep, of the reservoir. The divergent flow field close to the point-source injectors in doublet systems is not effective in providing a uniform sweep, but flow from parallel wells or from stimulated parallel wells offers a better prospect of establishing a uniform flow field. In the oil and gas industry, the drilling and stimulation of parallel, and typically horizontal, wells has been developed to considerable success for unconventional reservoirs, over the past decade. In this work, a new stimulation strategy is explored that comprises the development of two parallel and high permeability manifolds each as a separate injection zone and production zone. It is anticipated that this stimulation schedule will generate analogous results to the drilling of two horizontal wells and therefore in increasing the flow sweep efficiency from the injection zone towards the production zone.
2. Model setup

We explore various stimulation strategies to determine their effect on both the magnitude and longevity of thermal recovery rates for a given reservoir with a defined pre-existing fracture network. For these reservoirs, the fracture permeability of the network evolves subject to the influence of the change in stress state, including normal closure, shear dilation, and the potential for fracture walls to lose contact. Coupled thermal effects exert a strong effect in changing the fracture normal stress with a concomitant influence on both fracture-normal dilation and on shear-slip-induced dilation and in ultimately modifying permeability. This work includes both the influence of an initial stimulation followed by a production phase – throughout which permeability evolves in response to the evolving effective stress regime. In particular, we explore the potential that the stimulation may develop hydraulically-interconnected manifolds along the axis of a supposed horizontal well (E-W direction) that in turn may be used to develop a uniform flow field across the reservoir (in the N-S direction) – to a second parallel manifold also aligned in the E-W direction. Another stimulation strategy is to develop permeable manifolds in the N-S direction by connecting the drilling wells in N-S direction. These two behaviors will be different due to the directional characteristics of both the stress regime and the topology of the fracture network that is overprinted on the well pattern. The influence of fracture stimulation direction is illustrated through a comparison of the different development scenarios.

2.1 Reservoir Model

A reservoir containing a discrete fracture network is created using an updated discrete fracture network model using the equivalent continuum simulator TF_FLAC3D. Figure 4-1a shows one scenario of the resulting fracture network in a reservoir $1500m \times 1500m \times 10m$. The initial
pressure distribution is uniform at 10 MPa, and the initial homogenous rock temperature is 250°C. The minor principal stress is imposed at 19.5 MPa in the N-S direction, while the major principal stress is 30 MPa in the E-W direction. The fractures comprising the network are sub-vertical and are oriented (strike) at 45 degrees and 120 degrees with respect to the North direction, respectively. There are 1000 fractures for each set. The length of fractures follows a lognormal distribution with a mean length of 80 m (Figure 4-2) [de Dreuzy et al., 2001]. A power law is implemented to correlate fracture trace length $l$ with the fracture aperture $b_i$ [Olson, 2003] as,

$$b_i = 1.25 \times 10^{-5} \times l^{0.8}$$

The fracture density $\rho_f$ ($1/m$) is expressed as the ratio of fracture surface area to the volume of matrix rock, as,

$$\rho_f = \frac{\sum A'_i}{V_{\text{rock}}}$$

where $A'_i$ is the surface area of the $i_{th}$ fracture, and $V_{\text{rock}}$ is the total rock volume. The fracture density in this particular case is equal to 0.09 m$^{-1}$.

The geometries of the pre-existing discrete fracture networks are presented in Figure 4-1. It is assumed that the DFN consists of two fracture sets. The initial permeability of the fracture network is of the order of $10^{-17}$ to $10^{-16}$ m$^2$. The fractures in each fracture set are each oriented at a uniform angle. Two fracture geometries are chosen. The first is where both sets of fractures are favorably oriented for slip and strike 045° and 120° clockwise from the North (Figure 4-1a) [Odling, et al, 1999; Riahi and Damjanac, 2013]. The second geometry is where one set is less favorably aligned for slip where the fractures strike 020° and 135° with respect to the North direction (Figure 4-1b). The impact of fracture orientations on thermal transport and heat recovery is assessed through the comparison between these two fracture geometries. The
distributions of fracture lengths for both scenarios are the same, leaving fracture orientation relative to the stress field as the only significant variable.

Table 4-1 Rock and fracture properties used in the simulation.

<table>
<thead>
<tr>
<th>Parameter (unit)</th>
<th>Magnitude</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shear modulus, G (GPa)</td>
<td>15</td>
</tr>
<tr>
<td>Poisson’s ratio, $\nu$</td>
<td>0.25</td>
</tr>
<tr>
<td>Undrained Poisson’s ratio, $v_{\text{undrain}}$</td>
<td>0.33</td>
</tr>
<tr>
<td>Matrix permeability, $k_m$ ($m^2$)</td>
<td>$1.0 \times 10^{-18}$</td>
</tr>
<tr>
<td>Fracture permeability, $k_f$ ($m^2$)</td>
<td>$10^{-17} \sim 10^{-16}$</td>
</tr>
<tr>
<td>Matrix porosity, $\phi_m$</td>
<td>0.01</td>
</tr>
<tr>
<td>Fracture porosity, $\phi_f$</td>
<td>0.1</td>
</tr>
<tr>
<td>Biot coefficient, $\alpha$</td>
<td>0.88</td>
</tr>
<tr>
<td>Water viscosity, $\mu$, (Pa.s)</td>
<td>$3.547 \times 10^{-4}$</td>
</tr>
<tr>
<td>Fluid compressibility, ($MPa^{-1}$)</td>
<td>$4.2 \times 10^{-4}$</td>
</tr>
<tr>
<td>Thermal expansion coefficient of solid, $\alpha_s$, ($K^{-1}$)</td>
<td>$2.4 \times 10^{-5}$</td>
</tr>
<tr>
<td>Thermal diffusivity of intact porous rock, $c_s$, ($m^2/s$)</td>
<td>$1.1 \times 10^{-6}$</td>
</tr>
<tr>
<td>Heat capacity of fluid, $c_w$, ($Jkg^{-1}K^{-1}$)</td>
<td>4200</td>
</tr>
<tr>
<td>Initial reservoir temperature, $T_0$, ($K$)</td>
<td>523</td>
</tr>
<tr>
<td>Injection water temperature, $T_{\text{inj}}$, ($K$)</td>
<td>323</td>
</tr>
<tr>
<td>Initial joint normal stiffness, $k_n$, ($GPa/m$)</td>
<td>0.5</td>
</tr>
<tr>
<td>Initial joint shear stiffness, $k_s$, ($GPa/m$)</td>
<td>50</td>
</tr>
<tr>
<td>In-situ stress ($MPa$) – E-W direction</td>
<td>30</td>
</tr>
<tr>
<td>In-situ stress ($MPa$) – N-S direction</td>
<td>19.5</td>
</tr>
<tr>
<td>Initial reservoir pore pressure, $p_0$, ($MPa$)</td>
<td>10</td>
</tr>
<tr>
<td>Injection pressure, $p_{\text{inj}}$, ($MPa$)</td>
<td>15</td>
</tr>
<tr>
<td>Fracture friction angle, (degrees)</td>
<td>$35^\circ$</td>
</tr>
<tr>
<td>Fracture dilation angle, (degrees)</td>
<td>$3^\circ$</td>
</tr>
<tr>
<td>Fracture cohesion, $C$, ($MPa$)</td>
<td>0</td>
</tr>
<tr>
<td>Production pressure, $p_{\text{pro}}$, ($MPa$)</td>
<td>7</td>
</tr>
</tbody>
</table>
Figure 4-1 (a) Discrete fracture network distribution with orientations striking 045 and 120 degrees with respect to the North, (b) and a second discrete fracture network distribution with orientations at 020 and 135 degrees with respect to the North. These two orientations are chosen to evaluate the impact of fracture network geometry on fluid flow and heat transport.
2.2 Stimulation – production case

The influence of stimulation strategy is investigated by stimulating the reservoir in multiple different modalities. Figure 4-2 schematically shows the two predefined stimulation scenarios: the first produces two parallel manifolds in the E-W direction (Figure 4-2a), while a second alternative is to develop two parallel manifolds in the N-S direction (Figure 4-2b) respectively. These parallel manifolds (Figure 4-2a) are then used to promote a uniform flow regime across the reservoir. In this there are four potential well sites at points A (500, 1000), B (1000, 1000), C (500, 500), D (1000, 500). In terms of stimulation in the E-W direction, only the two injection wells at A and B are initially stimulated at 20 kg/s for 10 hours [Darnet et al. 2006]. Then the other two wells at C and D are stimulated, again at 20 kg/s for 10 hours, while the injection wells at A and B are shut-in. The developed manifolds result in enhancing the fracture permeability horizontally between A and B and C and D, separately. Similarly, the N-S stimulation scenario is designed to first develop a manifold between injection wells at B and D with the same constant injection rate of 20 kg/s for 10 hours, and then to switch to inject at same rate into A and C for 10 hours (Figure 4-2b). Then the eventual production scenario is designed to place two injectors at wells C and D at a constant pressure of 15 MPa, while the producers are located at A and B points at a constant pressure of 7 MPa (Figure 4-2c). In either instance, the pressure drop across the reservoir is 8 MPa.
Table 4-2 Case studies designed in the study for different stimulation – production scenarios

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Stimulation Scenario</th>
<th>Fracture Orientation, degree</th>
<th>Fracture Friction Angle, degree</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Stimulation (E-W)</td>
<td>020 - 135</td>
<td>35 - 35</td>
</tr>
<tr>
<td>2</td>
<td>No Stimulation</td>
<td>020 - 135</td>
<td>35 - 35</td>
</tr>
<tr>
<td>3</td>
<td>Stimulation (E-W)</td>
<td>045 - 120</td>
<td>35 - 35</td>
</tr>
<tr>
<td>4</td>
<td>Stimulation (E-W)</td>
<td>045 - 120</td>
<td>35 - 75</td>
</tr>
</tbody>
</table>

Table 4-2 indicates the separate cases explored in this study. The fracture properties in Case 2 are identical with those in Case 1, however there is no initial stimulation performed. The influence of stimulation is revealed by comparing Case 2 against Case 1. The results in Case 3 with a different fracture orientation of 045 –and- 120 degrees illustrates the impact of fracture orientation on heat recovery, as the fracture aperture is stress sensitive due to the variation of fracture orientation. Case 4 is implemented to examine the influence of fracture failure potential in the production of heat from the reservoir. In this, a 75 degree friction angle is set for the secondary set of fractures in Case 4 to evaluate the influence where one set of fractures has less potential to slip.
3. Results Discussion

The magnitude of permeability evolution and the resulting influence on heat energy extraction are the primary variables in this study. The potential optimization strategy is explored by investigating the relationship between the permeability enhancement and the resulting efficiency of heat recovery. The stimulation prior to the production phase develops parallel hydraulically interconnected manifolds along the horizontal axis of the injection wells in the E-W direction. This, in turn, will ultimately return a uniform flow sweep across the reservoir during the
production stage, from the injector zone to the second parallel manifold in the producer zone in the N-S.

Figure 4-3 shows a comparison of the evolution in fracture permeability for the various fracture properties and stimulation scenarios. Figures 4-3(a) and 4-3(b) represent the initial fracture permeability distribution for the fractures oriented at 045 – 120 degrees and 020 – 135 degrees with respect to the North direction. The initial equivalent permeability of the fracture network is in the range of $10^{-17}$ to $10^{-16}$ m$^2$. The directional fracture permeability is defined as a permeability tensor $k_{ij}$ accommodating the orientation of the fractures and the explicit fracture volume intersecting an element block as,

$$k_{ij} = \sum_{ni} \frac{1}{12} \left( \frac{V_{ratio}}{b_{ini}} b^3 n_i^2 \delta_{ij} - \frac{V_{ratio}}{b_{ini}} b^3 n_j n_i \right)$$

where $b_{ini}$ is the initial aperture of fracture, $n$ is the unit normal to each fracture, $V_{ratio}$ is the volumetric ratio of the truncated fracture over the element volume.

The fracture permeability distribution following the initial E-W stimulation for the fractures oriented at 045 – 120 degrees is presented in Figure 4-3(c). The two black dashed circles show the development of two permeable horizontal manifolds created in the northern and southern portions of the reservoir. The fracture permeability is significantly improved by ~3 orders magnitude following the stimulation, due to an effective increase in fracture aperture of the order of 10 times during the extensile loading. Since the fractures are oriented close to the E-W direction, the fracture permeability along this direction of stimulation is significantly enhanced (E-W direction).

The dashed black circle in Figure 4-3(d) shows the principal area where the fracture permeability is enhanced following stimulation for fracture orientations at 020 – 135 degrees. The red area representing the permeability-enhanced regime is oriented at an azimuth of ~060 degree.
Moreover, the area of permeability enhancement is smaller than that in Figure 3(d), in this case since the fractures (020 – 135 degrees) are not favorably oriented along the stimulation direction (E-W).

Figure 4-3 Contour plots of equivalent rock mass permeability evolution, (a) initial fracture permeability distribution for fractures oriented 045 – 120, (b) initial fracture permeability distribution for the scenario of fractures oriented 020 – 135, (c) development of two interconnected manifolds after the E-W stimulation for fractures oriented 045 – 120, (d) fracture permeability distribution after the E-W stimulation for fractures oriented 020 – 135 degrees.

The corresponding cases for the generation of power from the various stimulations are presented in Figure 4-4. The magnitude of instantaneous electric power generation $W_h$ is calculated as a product of flow rate and the enthalpy of the water as [Pruess, 2006],
\[ W_h = \sum_{i=1}^{n} \alpha q_{pro}^i (h_{pro} - h_{inj}) \]

where \( \alpha \) is the heat utilization efficiency, assumed to be 0.45 in this calculation [Sanyal and Butler, 2005]. \( h_{pro} \) is the water enthalpy at the production well with the highest enthalpy in this work equals to \( 1.08 \times 10^6 \, j/kg \) (250°C), \( h_{inj} \) is the enthalpy of the injected cold water, which is equal to \( 2.0 \times 10^5 \, j/kg \) and \( q_{pro}^i \) is the flow rate in the \( i \)th production well (kg/s).

Figure 4-4 Comparison of total electric power generation from two production wells between all five cases. The magenta curve (Case 4) is for fractures oriented 045 – 120 degrees with E-W stimulation and this returns the highest electric power generation. Case 3 shown by the blue curve for fractures oriented 020 – 135 degrees but without stimulation indicates the lowest power generation.
Figure 4-5 Evolution of flow rate and water temperature (enthalpy) in the two production wells. Plots in the left column (a, c, e, g, i) represent the flow rate evolution in the two production wells for the five cases (1-5), plots in the right column (b, d, f, h, j) represent the evolution of water temperature in the two production wells respectively.

The results indicate that Case 4 (fractures oriented at 045 – 120 degrees) returns the highest power output, sustaining the highest power generation within 10 years. The peak magnitude of generated power from the two production wells is maintained around 14 MWe. The evolution of the flow rate and corresponding water temperature from Case 4 suggests that the horizontal E-W stimulation is the most effective in maintaining both a high production flow rate and elevated temperature of outflow water at the highest level (Figure 4-5 (g) and (h)).

The predefined high friction angle of 75 degrees for the second fracture network in Case 5 is intended to lock this fracture set as resistant to failure. The corresponding results for power generation indicate the reduced potential of shear failure that impairs the magnitude of power generation by decreasing the fracture permeability.

The lowest intensity of power generation (Figure 4-4) represents Case 5 (no stimulation performed). Even though the temperature at the production well is maintained with the least thermal drawdown (Figure 4-5f), the flow rate in the production wells are small and uneconomical for power generation. Therefore this indicates that horizontal permeable manifolds are potentially both efficient and necessary for economical heat extraction from these geothermal reservoirs.

The distributions of rock temperature are presented in Figure 4-6 for the previous five cases at the same elapsed time of $t = 6.34 \text{ years}$. Examining the temperature distribution in the reservoir yields some impression of the best performance of heat production with the best heat sweep efficiency. Figures 4-6 (a) and (b) show the distributions of rock temperature for fractures orientated 020 – 135 degrees with stimulation along in the E-W and then the N-S directions,
separately. The cooled volume in Figure 4-6(b) is slightly smaller than that in Figure 6(a). The distribution of rock temperature in Figure 4-6(a) and (b) indicate a sharper thermal front propagating from injector to producer. The cooling regime for the case without stimulation (Figure 4-6(c)) is the smallest among all the cases studied. The thermal extraction is limited to around the injection wells due to the low reservoir permeability. Figure 4-6(d) shows the case with the most complete heat energy depletion in the reservoir for Case 4. The reservoir between the injection wells and the production wells has been cooled both significantly and uniformly - the rock temperature has been cooled to the temperature of injected water. This cooling response reinforces the results for the largest heat generation from Case 4. If one set of fractures is less able to slip, then the cooling path would follow the major conductive fractures as shown in Figure 4-6(e).
Figure 4-6 Contour of rock temperature distribution at $t = 6.34$ years. (a) Case 1 fracture orientations 020 – 135 degrees after E-W stimulation, (b) Case 2 fracture orientations 020 – 135 degrees after N-S stimulation, (c) Case 3 without stimulation, (d) Case 4 fracture orientations 045 – 120 degrees after E-W stimulation, (e) Case 5 fracture orientations 045 – 120 degrees with friction angle 035 – 75 degrees after E-W stimulation.
Fracture density is a crucial factor in influencing the extraction of heat energy. In this section, another reservoir geometry with fewer fractures is developed to examine the impact of fracture density on power generation. Figure 4-7(a) shows the distribution of fractures in the reservoir.
Two sets of fractures oriented at 045 – 120 degrees are arranged with 250 fractures in each set. The corresponding fracture density $\rho_f$ is equal to 0.0223 $m^{-1}$, which is only one-quarter of the previous reservoir conditions with 1000 fractures. Figure 4-7(b) represents the distribution of initial fracture permeability. The stimulation and subsequent production schedules are identical for both cases.

![Power generation evolution comparisons between the Case 4 with 1000 fractures $\rho_f = 0.089 \, m^{-1}$ and the case with 500 fractures $\rho_f = 0.0223 \, m^{-1}$.](image)

The evolution of instantaneous electric power generation for the low fracture density case is presented in Figure 4-8. The comparison between the different fracture densities reveals that an increased fracture density can significantly enhance the generated power. The more permeable reservoir with a larger fracture density has the advantages in collecting higher flow rates, and
avoiding short circuit during the heat extraction. The total power generation in the higher fracture density condition yields a peak magnitude around 14.5 MWe, while the peak power generation in the smaller fracture density condition reaches only 11.5 MWe.

Moreover, the resulting lower power generation in the small fracture density end-member case is not only due to the low flow rates in the production wells, but also the response to the early thermal breakthrough in the production wells. The temperature evolution of produced water for both cases is presented in Figure 4-9. The black line shows the water enthalpy and temperature for the produced water in Case 4 for the reservoir with a high fracture density, while the blue line depicts the evolution of produced water enthalpy and temperature in the low fracture density condition (Case 6). It is obvious that the thermal drawdown response in the production well for
the high fracture density case started significantly earlier than that for the low fracture density case. The sparse distribution of the fracture network prevents the cold water from picking up sufficient heat energy from the surrounding (and more distant) rock. The early thermal breakthrough due to the induced short circuit is not a favorable scenario for geothermal energy production, either.

The rock temperature distribution at $t = 6.34 \text{ years}$ in Figure 4-10 further reinforces the response of the short circuit in the reservoir with lower fracture density. The narrow cooling path from the bottom injectors to the top producers indicates a response of preferred fracture channeling during heat transport. It can be concluded that the fracture density has a strong impact on the heat energy transport in geothermal reservoirs. Larger fracture density increases the flow rate in the production well, and also increases the heat circuit length to substantially improve sweep efficiency.

Figure 4-10 Contour of rock temperature at $t = 2.0 \times 10^6 \text{s}$ for the lower fracture density case $\rho_f = 0.0223 \text{ m}^{-1}$. 
4. Conclusions

The previous case studies focus on examining the impact of fracture orientation, stimulation strategy, and the fracture density in enhancing the permeability and heat energy extraction from geothermal reservoirs. The best production optimization strategy is obtained from a series of simulations aimed to enhance both the magnitude and longevity of thermal recovery rates.

Reservoir stimulation is demonstrated to be efficient in significantly enhancing the generated power, compared against the results without stimulation. In this study, the eventual production schedule is designed to generate a fluid sweep path in the direction of the minor principal stress (N-S direction). The best optimization that results in the highest power generation is to create two parallel permeable manifolds along the major principal stress direction – in the example here, in the E-W direction. The parallel manifolds become hydraulically interconnected along the axis of the horizontal injection wells in the E-W direction, which are analogous to horizontal wells that allow a uniform sweep of fluids between the zones. The long term production results verify that the manifolds return an improved heat sweep efficiency. Furthermore, the fracture orientation is either very important in influencing the stimulation result. Fractures oriented at 045–120 degrees result in the greatest fracture permeability enhancement along the stimulation direction. Therefore, the developed manifolds with fractures oriented at 045–120 degrees are more permeable and conductive, compared to the case with fractures oriented at 020-135 degrees. Additionally, the fracture density either has direct impact in the heat extraction. The larger fracture density (small fracture spacing) has significant advantages for the heat production by increasing the flow rate in the production wells. The evolution of water temperature in the production well illustrates that the early thermal breakthrough tends to occur in the reservoir with lower fracture density.
Acknowledgement

This work is a partial result of support from the US Department of Energy under project DOE-DE-343 EE0002761. This support is gratefully acknowledged.

Reference


Watanabe, K., Y. Niibori, and T. Hashida (2000), Numerical study on heat extraction from supercritical geothermal reservoir, paper presented at Proceedings World Geothermal Congress.
Chapter 5 Conclusions

We explore the potential for reactivation of a major strike-slip fault in an enhanced geothermal systems (EGS) reservoir. The mechanisms causing fault reactivation and seismic slip are systematically investigated together with the critical controlling factors influencing slip magnitude and timing. The results indicate the principal influence of mechanical and hydrological effects in inducing fault reactivation in the short-term, and the impact of thermal stress in inducing long-term seismic slip. The permeability of the fault is insensitive to timing and magnitude of the initial H-M slip, because the transmission of fluid to the fault, from the injection is controlled by the permeability of stimulated host medium. The induced thermal shrinkage stress from the thermal drawdown does play an important role in unloading the stress field by reducing the maximum in-situ stress, and thereby reduce the shear strength, resulting in secondary seismic slip. The magnitude of the second seismic slip event is governed by the temperature difference between the injected fluid temperature and the ambient domain temperature.

To better understand the relationship between heat transfer and the induced late stage fault reactivation, including the timing and magnitude of induced seismicity, a non-dimensional model is developed to characterize the evolution of heat transfer in a fractured geothermal reservoir. The evolution of water temperature and mean temperature in the rock is conditioned by dimensionless parameters representing the flow rate $Q_D$ and time $t_D$. The dimensionless flow rate $Q_D$ is controlled by the in-situ fracture spacing $s$, prescribed mass injection rate $q$ and reservoir geometry and influences the thermal drawdown response of the reservoir. The primary control parameter $Q_D$ transforms dimensionless timing and temperature data into two boundary
asymptotic responses. These two bounding asymptotic behaviors refer to the situations of heat transfer dominated by heat conduction where the drawdown gradients of dimensionless temperatures with time become asymptotically and infinitely steep (vertical) around \( t_d/Q_d \sim 1 \), when the \( Q_d \) values decreases below \( 2.6 \times 10^{-4} \). When \( Q_d \) reaches \( 2.6 \times 10^4 \), the curves become asymptotic to a horizontal line anchored at \( T_d \sim 1 \). This represents the case where the velocity of fluid in the reservoir is sufficiently rapid that heat transfer from the rock to the fluid is conduction limited and small. This results in an early cold water breakthrough at the outlet and uniform thermal drawdown in the rock. The situation with a lower magnitude \( Q_d \) (<5.2 in this model configuration) yields a uniform propagation of the thermal front, while the case with larger magnitude \( Q_d \) (>2.6 \times 10^7) produces a more uniform thermal distribution across the whole reservoir without a distinct thermal front. Under the condition of propagation of a uniform thermal front, the timing for fault reactivation is determined as the thermal front arrives at the fault. The spatial thermal gradient adjacent to the front (and then arriving at the fault) is the principal factor defining the timing of triggered seismicity. As the dimensionless ratio \( Q_d \) increases, accordingly the dimensionless timing for the onset of thermal-driven seismicity is also increased. Similarly, the magnitude of fault slip distance also grows with increments in \( Q_d \), since the cooled area of fault area that exhibits thermal stress changes is proportionally increased with an increase in \( Q_d \).

Since it has been identified that the fracture pattern has a direct influence on heat transfer and thermal propagation in the reservoir. To address this, an equivalent continuum model is developed to represent randomly distributed fractured masses and to investigate the evolution of stress-dependent permeability of fractured rock masses. The model incorporates both mechanical crack tensor and permeability tensor approaches to characterize the pre-existing fractures, accommodating the orientation and trace length of fractures. Compared to other discrete fracture
models, the advantages of this model are primarily represented in simulating the large scale reservoir including the long term coupled thermal-hydraulic-mechanical response, and also without any dependence in the fracture geometry and gridding. The accuracy of simulator has been evaluated against other discrete fracture models by examining the evolution of fracture aperture and injection pressure during injection. The simulator is shown capable of predicting the evolution of the fracture normal aperture, including the state of fracture normal closure, shear dilation, and out of contact displacements under tensile loading.

The model is then applied to the discrete fracture network representing a prototypical reservoir to optimize long term geothermal production. Reservoir stimulation is demonstrated to be efficient in significantly enhancing the generated power, compared against the results without stimulation. In this study, the eventual production schedule is designed to generate a fluid sweep path in the direction of the minor principal stress (N-S direction). The best optimization that results in the highest power generation is to create two parallel permeable manifolds along the major principal stress direction. The parallel manifolds become hydraulically interconnected along the axis of the horizontal injection wells, which are analogous to horizontal wells that allow a uniform sweep of fluids between the zones. The long term production results verify that the manifolds return an improved heat sweep efficiency. Furthermore, the fracture orientation is either very important in influencing the stimulation result. Fractures oriented at 045–120 degrees result in the greatest fracture permeability enhancement along the stimulation direction. Therefore, the developed manifolds with fractures oriented at 045–120 degrees are more permeable and conductive, compared to the case with fractures oriented at 020-135 degrees. Additionally, the fracture density either has direct impact in the heat extraction. The larger fracture density (small fracture spacing) has significant advantages for the heat production by increasing the flow rate in the production wells. The evolution of water temperature in the production well illustrates that the early thermal breakthrough tends to occur in the reservoir with lower fracture density.
Appendix

Breakdown Pressures due to Infiltration and Exclusion in Finite Length Boreholes

Abstract

The theory of effective stress suggests that the breakdown pressure of a borehole should be a function of ambient stress and strength of the rock, alone. However, experiments on finite-length boreholes indicate that the breakdown pressure is a strong function of fracturing fluid composition and state as well. The reasons for this behavior are explored including the roles of different fluid types and state in controlling the breakdown process. The interfacial tension of the fracturing fluid is shown to control whether fluid invades pore space at the borehole wall and this in turn changes the local stress regime hence breakdown pressure. Interfacial tension is modulated by fluid state, as sub- or supercritical, and thus gas type and state influence the breakdown pressure. Expressions are developed for the breakdown pressure in circular section boreholes of both infinite and finite length and applied to rationalize otherwise enigmatic experimental observations. Importantly, the analysis accommodates the influence of fluid infiltration or exclusion into the borehole wall. For the development of a radial hydraulic fracture (longitudinal failure) the solutions show a higher breakdown pressure for impermeable relative to a permeable borehole. A similar difference in breakdown pressure exists for failure on a transverse fracture that is perpendicular to the borehole axis, in this case modulated by a parameter $\eta$, which is a function of Poisson ratio and the Biot coefficient. These solutions are used to rationalize observations for mixed-mode fractures that develop in laboratory experiments containing finite-length boreholes. Predictions agree with the breakdown pressure records recovered for
experiments for pressurization by CO\textsubscript{2} and Ar - higher interfacial tension for subcritical fluids requires higher critical pressures to invade into the matrix, while supercritical fluid with negligible interfacial tension have less resistance to infiltrate into the matrix and to prompt failure. This new discovery defines mechanisms of failure that although incompletely understood, provisionally link lower breakdown stresses with mechanisms that promote fracture complexity with the potential for improved hydrocarbon recovery.

Keywords: Fracture Breakdown pressure; Supercritical fluid; Subcritical fluid; Biot coefficient; Finite borehole length; Infiltration; Extraction

1. Introduction

The breakdown pressure is the critical pressure where failure occurs during borehole pressurization. Numerous attempts have been made to forecast the magnitude of breakdown pressure by analytical, semi-analytical and numerical approaches (Kutter, 1970; Newman, 1971; Tweed, 1973).

Initial attempts focused on an analytical formula to predict the breakdown pressure in impermeable rocks (Hubbert and Willis, 1957). Subsequent analyses extended this formula for fluid pressurization in permeable rocks (Haimson and Fairhurst, 1967). In this solution thermoelastic stressing was used as an analog to represent fluid pressurization (Timoshenko, 1951). The results from these two approaches and for these two conditions – impermeable versus permeable borehole walls - show two different bounding values: the breakdown pressure in permeable rock is always lower than that in impermeable rock.

This approach provides a pathway to explore pressurization rate effect on the breakdown process. Experimental approaches have shown that at higher pressurization rates, the breakdown pressure is also elevated (Solberg, 1980; Wu 2008; Zhengwen Zeng, 2002; Zoback, 1977). This
observation may be explained as the influence of a pressure diffusion mechanism (Detournay, 1992; Garagash, 1996), that requires a critical diffusive pressure to envelop a critical flaw length in the borehole wall.

All these approaches rely on Terzaghi's theory of effective stress (Biot, 1941), which predicts that failure will occur when the effective stress is equal to the tensile strength. Furthermore, this suggests that breakdown pressures should be invariant of fluid type (composition) or state (gas or liquid) since failure is mediated by effective stress, alone. However recent results (Alpern, 2012; Gan et al., 2013) suggest that fluid composition and/or state may influence breakdown pressure in an important manner. The flowchart in figure A-1 shows the methodology and workflow involved in this work. The blue dashed rectangle identifies the state of the fluid and its influence on the breakdown pressure. In this work, we develop an approach to explain the role of fluid composition or state on breakdown pressure based on prior observations of permeable versus impermeable borehole walls. In this approach the physical characteristics of the borehole remain the same for all fluid compositions, but the feasibility of the fluid either invading the borehole wall or being excluded from it changes with fluid state (subcritical or supercritical). An approach is developed based on Biot effective stress, to define breakdown pressure for supercritical/subcritical gas fracturing. The critical entry-pore pressure is governed by fluid interfacial tension (Bennion, 2006; Berry, 1971; Escobedo, 1996; Vowell, 2009), and the subcritical fluid breakdown pressure is shown to scale with the critical fluid invasion pressure. Breakdown pressures scaled in this manner agree with experimental observations.
Figure A-1 Workflow initiating from the injection of fluids in PMMA. The final conclusions are highlighted in the blue rectangle.

1 Experimental Observations

Fracturing experiments are reported on homogeneous cubes of Polymethyl methacrylate (PMMA; Alpern, 2012). Figure A-2a depicts the configuration of specimens used in the experiments. The pressurized fracturing fluid is injected through a drilled channel, which is analogous to the borehole. The induced hydraulic fractures are embedded in cubes 101 mm (4 in) and 121 mm (5 in) on side. The borehole diameter is 3.66 mm, and the cubes are stressed under biaxial conditions.
$\sigma_2$ in the horizontal direction and $\sigma_1$ in the vertical direction. During the experiment, the stress state is $\sigma_2 = \sigma_1$, and $\sigma_3 = 0$ in the borehole-parallel direction. Figure 2b shows the biaxial testing apparatus used in the experiment. Pore pressure is elevated with fluid injected under constant rate. Fracture occurs when the local borehole stresses exceeded the tensile strength of the PMMA, which is ~70 MPa. Figures A-2c and A-2d show the resulting fractures, both in the longitudinal mode (1c) and in transverse mode (2d).

Figure A-2 (a) Schematic of PMMA specimen used in the experiment. The drilled borehole is located in the center of sample and terminates in the center of the cube. (b) Biaxial loading frame. Beryllium-copper load cells measure the applied force. PMMA cube is centered between the rams and attached to a pore pressure line with access through the front face of the cube. (c) Resulting longitudinal fracture in the PMMA sample parallel to the borehole direction. (d) Induced transverse fracture perpendicular to the drilled borehole in the PMMA sample.
Six different fracturing fluids are injected in separate experiments and the borehole is pressurized to failure. The fluids used are: helium (He), nitrogen (N\textsubscript{2}), carbon dioxide (CO\textsubscript{2}), argon (Ar), sulfur hexafluoride (SF\textsubscript{6}), and water (H\textsubscript{2}O). Figure A-3 illustrates the states of injected fluids based on the experimental data. In the experiments the nitrogen, helium and argon are supercritical at fracture breakdown, while sulfur hexafluoride, CO\textsubscript{2} and water are subcritical. The CO\textsubscript{2} experiments return the largest breakdown pressure of 70 MPa, while the helium, nitrogen and argon fail at less than 33 MPa (Fig. A-4). The tensile strength of PMMA is ~70 MPa.

The following observations are apparent from the experimental results:

1. The maximum breakdown pressure is obtained for CO\textsubscript{2}, and is approximately equal to the tensile strength of the PMMA (~70 MPa).
2. The breakdown pressure for helium and nitrogen are approximately half of this tensile strength.

From these observations, we hypothesize that: (1) the factor-of-two differential in the breakdown stresses results from infiltration versus exclusion of fluids from the borehole wall and (2) the different behaviors of infiltration versus exclusion result from the state of the fluid, super-critical versus sub-critical.

This hypothesis is explored by first identifying the difference in breakdown pressure for infiltrating versus non-infiltrating fluids and is then related the propensity for infiltration via quantification of entry pressures in the borehole wall.

Figure A-4 Experiment results of fracture breakdown pressure under various injected fracturing fluid under the same experiment conditions (Alpern 2012).
2. **Analytical Solutions**

Consider a finite radius $r_w$ borehole in an elastic domain (external radius $r_e$) under internal fluid pressure $p_w$, with the domain confined under applied stresses $\sigma_{11}$ and $\sigma_{22}$. Breakdown pressure may be defined for fracture both longitudinal to the borehole and transverse to it and for conditions where fluid infiltration is either excluded or allowed, as follows.

2.1 **Fracture along Borehole (longitudinal fracture)**

For the longitudinal hydraulic fracture, breakdown occurs when the effective tangential stress is equal to the tensile strength. When the matrix is impermeable, there is no poroelastic effect and the solution is the Hubbert-Willis (Hubbert and Willis, 1957, H-W) solution,

$$p_w = -3\sigma_{22} + \sigma_{11} + \sigma_T$$

(1)

where $\sigma_{11}$ is the minimum principal stress, $\sigma_{22}$ is the maximum principal stress, $\sigma_T$ is the rock tensile strength, and $p_w$ is required breakdown fluid pressure.

When the porous medium is permeable, the Biot coefficient $\alpha$ reflects the poroelastic effect. It shows the strongest poroelastic effect when $\alpha = 1$. The tangential total stress $S_{\theta\theta}$ is defined relative to the effective tangential stress $\sigma_{\theta\theta}$ and Biot coefficient $\alpha$, as,

$$S_{\theta\theta} = \sigma_{\theta\theta} - \alpha p_w .$$

(2)

The total stresses at the wellbore boundary are obtained by superposition of the stress fields from the Haimson-Fairhurst solution (Haimson and Fairhurst, 1967, H-F) due to the total stresses $\sigma_{11}$ and $\sigma_{22}$, fluid pressure $p_w$, and Poisson ratio $\nu$ as,

$$S_{\theta\theta} = 3\sigma_{22} - \sigma_{11} - p_0 + p_w - \alpha p_w \frac{1 - 2\nu}{1 - \nu} .$$

(3)

The effective tangential stress at the wellbore $r_w$ is
Correspondingly, the breakdown pressure is

\[ p_w = \frac{-3\sigma_{zz} + \sigma_{11} + p_0 + \sigma_T}{1 + \eta} \]  

(5)

where \( \eta = \frac{\nu}{1-\nu} \).

This gives the appropriate breakdown pressures for cases where fluid is either excluded from the borehole wall (impermeable, equation (1), H-W) or allowed entry into the wall (permeable, equation (5), H-F).

### 2.2 Fracture across Borehole (transverse fracture)

Where the fracture is transverse to the borehole then breakdown occurs when the longitudinal stress exceeds the tensile strength. The longitudinal stress \( \sigma_{zz} \) may be determined from the radial and tangential stresses. For the impermeable case, pressurization of the borehole wall results in equal increments and decrements of the radial and tangential stresses, respectively. This results in no net change in longitudinal stress.

However, for the condition of fluid infiltration the longitudinal stress change is finite. The radial stress is defined as,

\[ \sigma_{rr} = -(1-\alpha) p_w. \]  

(6)

The stress-strain relationship is defined from Hooke’s law as,

\[ \varepsilon_{zz} = \frac{1}{E} \left[ \sigma_{zz} - \nu (\sigma_{rr} + \sigma_{\theta\theta}) \right]. \]  

(7)

Since the longitudinal strain \( \varepsilon_{zz} \) is zero, the longitudinal stress is
\[ \sigma_T = \sigma_z = \nu(\sigma_{rr} + \sigma_{\theta\theta}) = \nu \left[ (3\sigma_{zz} - \sigma_{11} - p_0) + p_w + \frac{\nu}{1-\nu} \alpha p_w - (1-\alpha) p_w \right]. \]

which may be transformed to give

\[ \sigma_z = \nu(3\sigma_{zz} - \sigma_{11} - p_0) + \frac{\nu}{1-\nu} \alpha p_w. \] (8)

Therefore the breakdown pressure in terms of longitudinal stress is equal to,

\[ p_w = \frac{-\nu(3\sigma_{zz} - \sigma_{11} + p_0) + \sigma_T}{\eta}. \] (9)

Comparing equations (5) and (9) illustrates that the breakdown pressure \( p_w \) for a longitudinal fracture is smaller than that for the transverse fracture. Therefore, fracture will always occur in the longitudinal direction before it can occur in the transverse direction, since

\[ \frac{1}{1+\eta} (\text{Longitudinal}) < \frac{1}{\eta} (\text{transverse}). \]

This is the case for a borehole of infinite length but not necessarily for the finite-length boreholes examined in the experiments of this work.

3. **Numerical Model**

The above expressions define the breakdown pressures for boreholes in infinite media. However the laboratory experiments are for blind and finite boreholes in cubic specimens. Therefore a finite element model is used to simulate the coupled process of fluid-solid interaction in geometries similar to the experiments. First, 2-D problems are explored to validate the model and then 3-D geometries are used to replicate the experiments and then to interpret the experimental observations.
### 3.1 2-D Model (plane strain)

A 2-D poro-mechanical model is used to represent the behavior with a central borehole within a square contour. The governing equations and boundary conditions are as follows.

**Governing equation:** Two governing equations represent separately the fluid flow and solid deformation processes. A Darcy flow model is applied to represent fluid flow with the Biot-Willis coefficient defined as,

\[
\alpha = 1 - \frac{K}{K_s}.
\]

(10)

where \( K_s \) and \( K \) are identified as the grain and solid bulk modulus.

The flow equation is,

\[
S_a \frac{\partial p}{\partial t} + \nabla \left[ -\frac{k}{\mu} \nabla p \right] = -Q_s.
\]

(11)

where \( p \) is fluid pressure (Pa), \( k \) is permeability (m\(^2\)), \( \mu \) is fluid viscosity (Pa.s) and \( S_a \) is the skeletal component of specific storage (Leake, 1997) \( S_a = \frac{1}{\rho g} \left( \frac{\alpha - n}{K_s} + \frac{n}{K_f} \right) \)

where \( n \) is the porosity, \( \rho_f \) the fluid density, \( g \) the gravitational acceleration, \( K_s \) the solid bulk modulus, and \( K_f \) the fluid bulk modulus, and \( Q_s \) defines the time rate of change of volumetric strain from the equation for solid displacements,

\[
Q_s = \alpha^* (d(u_x, t) + d(v_y, t)) .
\]

(12)

where the volume fraction of liquid changes with deformations \( u_x \) and \( v_y \).

The solid deformation equation is

\[
\frac{E}{2(1+\nu)} \nabla^2 u + \frac{E}{2(1+\nu)(1-2\nu)} \nabla^* (\nabla u) = \alpha \nabla p .
\]
where \( E \) is Young’s modulus, \( u \) is the displacement vector composed of orthogonal displacements \( u \) and \( v \) (m). The right hand side term \( \alpha \nabla p \) represents the fluid-to-structure coupling term in terms of the gradient of pressure, \( \nabla p \). Recalling the previous analytical solutions for the required breakdown pressure, the breakdown pressure for the longitudinal fracture during injection is

\[
p_{\text{w}} = \frac{-3\sigma_{22} + \sigma_{11} + p_0 + \sigma_T}{1 + \eta},
\]

and the breakdown pressure for the transverse fracture is

\[
p_{\text{w}} = \frac{-\nu(3\sigma_{22} - \sigma_{11} + p_0) + \sigma_T}{\eta}.
\]

The final combined constitutive equations are obtained as below,

\[
S_a \frac{\partial p_{\text{w}}}{\partial t} + \nabla \left[ -k \frac{\mu}{\nabla p_{\text{w}}} \right] = \left[ \alpha \left( d(u_x,t) + d(v_y,t) \right) \right].
\]

\[
\frac{E}{2(1 + \nu)} \nabla^2 u + \frac{E}{2(1 + \nu)(1 - 2\nu)} \nabla \cdot (\nabla u) = \alpha \nabla p_{\text{w}}.
\]

**Boundary Conditions:** The 2-D plane strain model geometry comprises a slice-cut across a section (see Fig. A-5). The left and basal boundaries A, B are set as roller condition with zero normal displacement (see Table A-1). The interior circular boundary represents the borehole where fluid pressure \( p_{\text{w}} \) is applied uniformly around the contour. Table A-2 shows the model input data. There is no confining stress applied to the outer boundary.

Table A-1 Hydraulic boundary and stress / displacement boundary applied in the COMSOL simulations.

<table>
<thead>
<tr>
<th>Boundary</th>
<th>Stress Boundary</th>
<th>Hydraulic Boundary</th>
</tr>
</thead>
<tbody>
<tr>
<td>A, B</td>
<td>( u_n = 0 )</td>
<td>( n \cdot K \nabla H = 0 )</td>
</tr>
<tr>
<td>C, D</td>
<td>free</td>
<td>( n \cdot K \nabla H = 0 )</td>
</tr>
<tr>
<td>E</td>
<td>free</td>
<td>( H = H_0 )</td>
</tr>
</tbody>
</table>
Figure A-5 2-D Model geometry (left) created in simulations, and applied hydraulic and displacement boundary conditions and initial conditions (right).

Table A-2 PMMA properties used in the simulation

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tensile strength, MPa</td>
<td>70</td>
</tr>
<tr>
<td>Fluid pressure, MPa</td>
<td>10</td>
</tr>
<tr>
<td>Poison ratio</td>
<td>0.36</td>
</tr>
<tr>
<td>Young's modulus, Pa</td>
<td>3.0e9</td>
</tr>
<tr>
<td>Biot coefficient</td>
<td>0-1</td>
</tr>
<tr>
<td>Solid compressibility, 1/Pa</td>
<td>8e-11</td>
</tr>
</tbody>
</table>
3.2 2-D Fracture Breakdown Pressure Results

The 2-D simulation results are used to validate the model for the two forms of fractures – longitudinal versus transverse – evaluated previously. The likelihood of either failure model is controlled by either the tangential effective stress (longitudinal failure) or the longitudinal effective stress (transverse failure).

Validation for 2-D longitudinal fracture: Failure occurs when the tangential effective stresses reach the tensile strength at a critical location. The blue curve in Figure A-6 reflects the tangential effective stress calculated from the analytical solution (equation (4)). The analytical results give satisfactory agreement with the simulation results as shown by the red points. The curve shows that for a stronger poroelastic effect (increasing $\alpha$), the tangential effective stress increases under the same fluid pressure.

![Figure A-6 Validation of 2-D tangential effective stress around borehole with various Biot coefficient factor (0.3~1).](image-url)
Figure A-7 shows the effect of Poisson ratio on breakdown pressure, where the Poisson ratio ranges from 0.1 to 0.5. For constant Biot coefficient, a lower Poisson ratio will elevate the required breakdown pressure. The H-W equation for the impermeable case provides an upper bound for the stress scaling parameter of \( 1/(1+\eta) \) as unity. For a Poisson ratio equivalent to that of PMMA \( (\nu = 0.36) \), the simulation results define a breakdown pressure for the strongest poroelastic condition \( (\alpha = 1) \) as 0.65 times that for impermeable case.

![Figure A-7](image)

**Figure A-7** Evolution of longitudinal fracture breakdown pressure coefficient with different Biot coefficients under various Poisson ratio (0~0.5) in permeable rocks.

**Validation for 2-D transverse fracture:** Figure A-8 shows the prediction of longitudinal effective stress under the constant fluid pressure of 10 MPa, and where the Biot coefficient varies from 0.2 to 1 for PMMA. The longitudinal stress from the simulation mimics the predictions from the analytical equation (8). This stress also grows with an increasing Biot coefficient. The
maximum longitudinal stress is lower than 6 MPa, which is half of the applied fluid pressure. The longitudinal stress is always lower than the tangential stress.

Figure A-8 Validation of 2-D longitudinal stress under different Biot coefficient factor (0.2-1).

The proportionality of the longitudinal effective stress to the Biot coefficient for a transverse fracture is shown in Figure A-9 (see Figure A-7). This proportionality coefficient corresponds to the denominator in equation (9) as $1/\eta$. The magnitudes of this coefficient are unbounded as the Biot coefficient approaches zero, signifying zero poroelastic effect and an infinitely large pressure required for failure. Although longitudinal fracturing is the preferred failure mode for infinite boreholes, for finite boreholes transverse fracturing may be a significant mode.
Figure A-9 Evolution of 2-D transverse fracture breakdown pressure coefficient under different Biot coefficient factor with Poisson’s ratio ranging from 0.1–0.5 (longitudinal stress).

3.3 **Breakdown Pressure for Finite 3-D Geometries**

The failure conditions for a finite length borehole are now explored. The stress accumulation at the end of the borehole will be a combination of the modes represented in the longitudinal and transverse failure modes. The experimental configuration is for a finite-length end-capped borehole that terminates in the center of the block. We represent this geometry (see Fig. A-10) with the plane with red set as roller boundaries (zero normal displacement condition).

For the finite borehole condition, the induced stresses may be shown to be a combination of the applied confining stress and fluid pressure. The exact functional dependence may be obtained by the superposition of the confining stress field and the influence of fluid pressure in a simplified model.
Assuming the wellbore radius is equal to a, the radial and hoop stresses for a unidirectional confining stress $\sigma_{11}$ are derived as below in polar coordinates (Jaeger and Cook, 1979),

$$\sigma_r + \sigma_{\theta\theta} = \sigma_{11} R \left(1 - Ar^{-2} e^{-2i\theta}\right) = \sigma_{11} \left(1 - Ar^{-2} \cos 2\theta\right)$$

$$\sigma_{\theta\theta} - \sigma_r + 2i\sigma_{r\theta} = \sigma_{11} \left[Br^{-2} - e^{2i\theta} + (Ar^{-2} + 3Cr^{-4})e^{2i\theta}\right]$$

Then the top equation gives

$$\sigma_{\theta\theta} - \sigma_r = \sigma_{11} \left[Br^{-2} - (1 - Ar^{-2} - 3Cr^{-4})\cos 2\theta\right]$$

$$\sigma_{r\theta} = -\frac{1}{2} \sigma_{11} \left[(1 + Ar^{-2} + 3Cr^{-4})\sin 2\theta\right]$$

Since the borehole boundary at r=a is traction-free, the stress $\sigma_r$ and $\sigma_{\theta\theta}$ must be vanish at r=a, therefore we can solve the equation to get the coefficients A, B, C to obtain the final expressions for the $\sigma_r$ and $\sigma_{\theta\theta}$.
\[ \sigma_{w} = \frac{\sigma_{11}}{2} (1 - \frac{a^2}{r^2}) + \frac{\sigma_{11}}{2} \cos 2\theta (1 - \frac{a^2}{r^2})(1 - \frac{3a^2}{r^2}) \]
\[ \sigma_{\theta \theta} = \frac{\sigma_{11}}{2} (1 + \frac{a^2}{r^2}) - \frac{\sigma_{11}}{2} \cos 2\theta (1 + \frac{3a^2}{r^2}) \]

At the borehole wall \( r = a \), the maximum and minimum stresses are at azimuths of \( \theta = 0^\circ \) and \( \theta = 90^\circ \), where tangential stresses around the borehole are \( 3\sigma_{11} \) and \( -\sigma_{11} \), respectively. If a uniform confining stress is applied by adding a second confining stress \( (\sigma_{11} - \sigma_{22}) \) then the longitudinal and hoop stresses are,
\[ \sigma_z = \nu(2\sigma_{11} + 0) \]
\[ \sigma_\theta = 2\sigma_{11} \]

If the borehole is now pressurized by fluid then the additional stresses are,
\[ \sigma_z = \nu(p_w + (-p_w)) \]
\[ \sigma_\theta = -p_w \]

Adding these two modes of solid stress and fluid pressure give the resulting longitudinal effective stress,
\[ \sigma_z = 2\nu\sigma_{11} + p_w - 0 \]

where the borehole end is capped (see Fig. A-11), the longitudinal stress induced by internal fluid pressure will be augmented due to the effect of fluid pressures acting on the ends of the borehole. This equation for longitudinal stress is extended for the general case of a finite borehole by introducing the stress concentration factors B and C to calculate the maximum longitudinal stress in mixed plane strain-plane stress conditions for the actual geometry as,
\[ \sigma_{z,\text{max}} = -2\nu B \sigma_1 + C p_w \]  \hspace{1cm} (13)

where B and C are coefficients recovered from the numerical modeling. The longitudinal effective stress is calculated at the end of borehole where fluid pressure is applied to obtain the longitudinal stress concentration factor (see Figure. A-11). If confining stress is applied alone
(without internal fluid pressure) then the geometric scaling coefficient for our particular geometry and for the maximum tensile tangential stress is $B=1.32$.

Figure A-11 shows the spatial distribution of the ratio $\sigma_e / p_w$ in the domain. The maximum value represents the coefficient $C$ in equation (13). Based on the above results: $C_{\text{permeable}} = 2.756$ and $C_{\text{impermeable}} = 1.328$. Assuming the tensile strength is 70 MPa, then breakdown pressure under experimental conditions is given as,

3D-impermeable scenario

$$p_w = 0.715\sigma_e + 52.7$$

(14).

3D-permeable scenario

$$p_w = 0.344\sigma_e + 25.4$$

(15).

Equations (14) and (15) indicate that the impermeable breakdown pressure is still approximately twice as large as that for the permeable case, which is congruent with experimental observations.

Figure A-11 Spatial distribution of longitudinal stress over fluid pressure for Biot coefficient equals to 0.9 (top) and 0 (down) respectively.
4. **Breakdown Pressure Hypothesis**

From the preceding analyses, congruent with two broad sets of experimental data, breakdown pressure is reduced by half where fluid infiltration can occur into the borehole wall. The numerical experiments are employed to demonstrate the effect of fluid infiltration or exclusion into the borehole wall and its corresponding influence on breakdown pressure magnitude. A hypothesis consistent with these observations is that fluid interfacial tension controls whether fluid invades the pore space at the borehole wall and this in turn changes the local stress regime hence breakdown pressure. Interfacial tension is modulated by fluid state, as sub- or supercritical, and thus gas type and state would be expected to influence the breakdown pressure.

A mixture of supercritical fluids is by definition miscible and will not be excluded from the pore space in the borehole wall by capillarity. Correspondingly, the breakdown pressure for a supercritical fluid should correspond to the permeable solution, whereas the response of a subcritical fluid should correspond to that of the impermeable solution. Equations (14) and (15) are the breakdown solutions for the experimental geometry of Figure 8 that is only approximated by infinite length boreholes and the analytical solutions of equations (5) and (9). In order to apply equations (14) and (15) to explore this hypothesis, the first important step is to identify the state of the injected fluids. The distribution of fluid states at failure is defined by the experimental fracture breakdown pressures and corresponding transition pressures to supercriticality, as shown in Figure 3. For the particular experimental conditions: nitrogen, helium and argon are all supercritical, while carbon dioxide, sulfur hexafluoride, and water are subcritical.

The concept of invasion pressure is invoked to represent the response in the borehole wall. If the fluid pressure in the borehole exceeds the critical invasion pressure $P_c$ then the fluids will penetrate the borehole wall and the hoop stress around the wellbore will be correspondingly elevated. We define the critical invasion pressure as the minimum pressure required to force
subcritical fluid into the pore space through the pore throat. This may be defined based on scaling arguments as a function of permeability, porosity and interfacial tension as in the Leveret function (J). This function is defined as,

\[ J = \frac{P_c}{\sigma} \sqrt{\frac{k}{n}}. \]  \(16\)

where \(\sigma\) is the fluid interfacial tension, \(k\) is the permeability, \(P_c\) is the critical invasion pressure and \(n\) is the porosity. For supercritical fluids interfacial tension is small and invasion of the borehole wall occurs at pressure \(P_c\) and results in a lowered breakdown pressure (relative to where the fluid is excluded). Thus, the critical invasion pressure \(P_c\) for a supercritical fluid is always smaller than the invasion pressure for the subcritical fluid.

Figure A-12 illustrates the relationship between critical invasion pressure and breakdown pressure for supercritical/subcritical fluids. Impermeable and permeable breakdown pressure solutions give two bounded values. There are three scenarios depending on the critical invasion pressure magnitude:

1. When the invasion pressure is lower than the breakdown pressure for the permeable solution, then both supercritical and subcritical fluids have the same breakdown pressure magnitude (see Fig. A-12-left);

2. When the invasion pressure is intermediate between the breakdown pressure for permeable and impermeable solutions, then the subcritical fluid invades and failure occurs at the critical pressure. In this case, supercritical fluids would result in failure at a pressure lower than the invasion pressure (see Fig. A-12-center).

3. When the invasion pressure is larger than the breakdown pressure for both permeable and impermeable solutions, then the supercritical fluid causes failure at a lower pressure than for the subcritical fluid (see Fig. A-12-right).
Figure A-12: Summaries of critical pressure vs. breakdown pressure under different invasion pressure $P_c$ value.

Considering that for invasion in any given material of defined permeability and porosity the ratio of invasion pressure to interfacial tension should be constant as,

$$
\zeta = \frac{P_b}{\sigma} = \frac{\text{MPa}}{\text{mN/m}} = \frac{10^6 \, \text{N/m}^2}{10^{-3} \, \text{N/m}} = \frac{10^9}{m}.
$$

(17)

Then Figure A-13 shows this ratio of breakdown pressure (rather than invasion pressure) to interfacial tension. This is evaluated from the magnitudes of interfacial tension in Table A-3. The value $\zeta$ is approximately constant for the subcritical fluids, where breakdown is modulated by this invasion parameter. Not only are these breakdown pressures constant but they are also of the expected magnitude of equation (17). For the supercritical fluids, there is no relationship for this parameter $P_i / \sigma$, suggesting that this behavior is independent of capillary entry pressures – as suggested by the hypothesis. This indicates that the interfacial tension for the subcritical fluid is large enough to govern the breakdown process, while the low interfacial tension of the supercritical fluid has no effect in controlling the breakdown process. For the case of argon where the fluid properties are supercritical the relation of equation (15) is used to define response against the available experimental data of Table A-4. Figure A-14 shows the match of the experimental results for Argon with the analytical data showing excellent agreement with the
permeable solution. Table A-5 summarizes the equations required to calculate fracture breakdown pressure under the conditions corresponding to impermeable/permeable media and resulting in longitudinal/transverse fractures.

Figure A-13 Distribution of ratio about invasion pressure to the interfacial tension under different fracturing fluids.

Table A-3 Comparison of supercritical / subcritical fluid interfacial tension (Berry 1971)

<p>| Table 3 Comparison of supercritical / subcritical fluid interfacial tension |
|---------------------------------|--------------------------|</p>
<table>
<thead>
<tr>
<th></th>
<th>Injected fluid</th>
<th>Interfacial tension (mN/m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supercritical fluids</td>
<td></td>
<td></td>
</tr>
<tr>
<td>N₂</td>
<td></td>
<td>7</td>
</tr>
<tr>
<td>He</td>
<td></td>
<td>0.37</td>
</tr>
<tr>
<td>Ar</td>
<td></td>
<td>2.13</td>
</tr>
<tr>
<td>Non-supercritical fluids</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SF₆</td>
<td></td>
<td>40-50</td>
</tr>
<tr>
<td>CO₂</td>
<td></td>
<td>72-40</td>
</tr>
<tr>
<td>H₂O</td>
<td></td>
<td>70-50</td>
</tr>
</tbody>
</table>
Table A-4 Breakdown pressure results in hydro-fracture experiment of Argon (Ar) injection under different confining stress from 5 MPa ~ 60 MPa

<table>
<thead>
<tr>
<th>Confining stress, MPa</th>
<th>Breakdown pressure, MPa</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>29.85</td>
</tr>
<tr>
<td>5</td>
<td>30</td>
</tr>
<tr>
<td>5</td>
<td>30.5</td>
</tr>
<tr>
<td>30</td>
<td>39.68</td>
</tr>
<tr>
<td>40</td>
<td>44.44</td>
</tr>
<tr>
<td>50</td>
<td>46.84</td>
</tr>
<tr>
<td>60</td>
<td>51.6</td>
</tr>
</tbody>
</table>

Figure A-14 Validations of 3-D permeable and impermeable breakdown pressure analytical solutions with experiment data.
Table A-5 Summary of expressions for breakdown pressure in different cases, i) permeable / impermeable medium, ii) fracture geometry, longitudinal / transverse.

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Condition</th>
<th>Expression</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Impermeable medium</td>
<td>$p_w = 0.715\sigma_r + 52.7$</td>
</tr>
<tr>
<td>2</td>
<td>Permeable medium</td>
<td>$p_w = 0.344\sigma_r + 25.4$</td>
</tr>
<tr>
<td>3</td>
<td>Longitudinal fracture</td>
<td>$p_w = \frac{-3\sigma_{zz} + \sigma_{11} + p_0 + \sigma_r}{1 + \eta}$</td>
</tr>
<tr>
<td>4</td>
<td>Transverse fracture</td>
<td>$p_w = \frac{-\nu(3\sigma_{zz} - \sigma_{11} + p_0) + \sigma_r}{\eta}$</td>
</tr>
</tbody>
</table>

5. Conclusions

Expressions are developed based on Biot effective stress theory to predict breakdown pressure for longitudinal and transverse fracture on finite length boreholes. These relationships are used to explore the physical dependencies of fracture breakdown pressures and show that an approximate factor of two exists in the breakdown stress where fluids either invade or are excluded from the borehole wall. These relationships are extended for finite length boreholes to replicate conditions for fracturing experiments in finite-volume samples. These solutions are then used to explain observations of variable breakdown stresses in experiments where all conditions are maintained constant except the composition and state of the fracturing fluids.

The difference in failure response is matched to the state of the fluid – supercritical versus subcritical. Observations suggest that fluid state controls interfacial properties and thereby governs fluid invasion into the matrix and the following breakdown process. The negligible interfacial tension in supercritical fluids allow easy invasion into the matrix, while the subcritical fluid with larger interfacial tension requires a higher pressure to invade and cause subsequent
breakdown of the borehole. For samples of equivalent permeability and porosity, the ratio of breakdown pressure to interfacial tension is constant for subcritical fluids – identifying the controlling influence on capillary behavior. Where fluids are supercritical, no similar relationship exists. To the contrary, where the fluid is supercritical, the breakdown pressures are uniformly those predicted where infiltration occurs into the borehole wall – approximately half of the tensile strength of the sample (Fig. A-3). These ensemble observations suggest the controlling influence of interfacial tension on breakdown pressure – at least at laboratory scale.

**Nomenclature**

\[ \alpha = \text{biot coefficient, dimensionless} \]

\[ \nu = \text{Poisson ratio, dimensionless} \]

\[ p_w = \text{fluid pressure, MPa} \]

\[ E = \text{Young’s modulus, MPa} \]

\[ \sigma_t = \text{rock tensile strength, MPa} \]

\[ \sigma_{\theta} = \text{tangential stress around wellbore, MPa} \]

\[ \sigma_r = \text{radial stress, MPa} \]

\[ \sigma_z = \text{longitudinal stress, MPa} \]

\[ k = \text{permeability, } m^2 \]

\[ \mu = \text{fluid viscosity, } Pa.s \]

\[ \rho_f = \text{fluid density, } kg/m^3 \]

\[ K_s = \text{grain bulk modulus, MPa} \]

\[ K = \text{solid bulk modulus, MPa} \]

\[ K_f = \text{fluid bulk modulus, MPa} \]
\[ r \] = wellbore radius, m

\[ P_c \] = critical invasion pressure, MPa

\[ n \] = porosity, dimensionless

\[ P_b \] = breakdown pressure, MPa

\[ u \] = displacement from solid deformation, m

Acknowledgement

This work is the result of support from the Chevron Energy Technology Company. This support is gratefully acknowledged. Originally communicated as paper 13-700 of the 47th US Symposium on Rock Mechanics/Geomechanics, San Francisco. We appreciate the permission of the American Rock Mechanics Association to publish this paper.

References

Alpern, J.S., Marone, C. and Elsworth D., 2012, Exploring the physicochemical process that govern hydraulic fracture through laboratory experiments, in 46th US Rock Mechanics/Geomechanics Symposium, edited, Chicago, IL, USA.

Bennion, B., 2006, The impact of Interfacial Tension and Pore Size Distribution/Capillary Pressure Character on CO\textsubscript{2} relative permeability at Reservoir Conditions in CO\textsubscript{2}-Brine Systems, in SPE/DOE Symposium on Improved Oil Recovery, edited, Society of Petroleum Engineer, Tulsa, Oklahoma, U.S.A.


Vowell, S., 2009, Microfluids: The Effects of Surface Tension. Physics 486


VITA – Quan Gan

Education

China University of Geoscience Beijing   Petroleum Engineering  B.S.  2006-2010
Penn State University   Petroleum Engineering  M.S.  2010-2012
Penn State University   Energy and Mineral Engineering Ph.D. 2015

Working Experience

1  Summer Intern at Chevron Energy Technology Company   May. 2014 —— Aug. 2014
2  Summer Field Engineer Intern at Sinopec (China National Petroleum Corporation)

Teaching Experience

Contaminant Hydrology, Co-Instructor. Senior level undergraduate course, Penn State. 2014

Research Interests

Quan Gan has expertise in the area of computation Geomechanics, fluid transportation, heat transportation in fractured porous medium, fault / rock mechanics, and the coupled modeling application in the conventional petroleum reservoir engineering, geothermal engineering.

Selected Publications


Conference Proceeding