ANALYSIS OF HYDROMECHANICAL RESERVOIR RESPONSE DURING FLUID CIRCULATION AT THE FENTON HILL ENHANCED GEOTHERMAL SYSTEM TEST SITE

Jack H. Norbeck[1], Mark W. McClure[2], and Roland N. Horne[1]

[1] Department of Energy Resources Engineering, Stanford University, 367 Panama St., Stanford, CA, USA 94305

[2] McClure Geomechanics, LLC, 555 Bryant Street, #185, Palo Alto, CA, USA 94301

jnorbeck@stanford.edu

Keywords: *hydraulic fracture, shear stimulation, hydraulic stimulation, enhanced geothermal system*

ABSTRACT

The Fenton Hill Enhanced Geothermal System (EGS) test site was the first EGS project in the world. The major accomplishments of the project include the successful hydraulic stimulation of two deep wells creating a flow connection, fluid circulation through the geothermal reservoir for several months, and generation of electricity. We analyzed multiple datasets to develop a conceptual model of the Fenton Hill EGS fractured reservoir system. In a previous study, we analyzed and modeled the stimulation phase of the project with a fully-coupled fluid flow and fracture mechanics reservoir simulator. In this work, we investigated the two main fluid circulation experiments performed at the site.

During the fluid circulation phase, our simulation results were consistent with the reported data in three distinct ways: 1) the overall reservoir impedance was improved by operating the production well at higher back-pressure, 2) the difference between injected and produced fluid volumes reduced over time, and 3) the accessible reservoir volume grew larger over time. These results suggest that our conceptual model may be appropriate for the Fenton Hill EGS site.

1. INTRODUCTION

This work was performed as part of a collaborative effort led by the US Department of Energy (DOE) Geothermal Technologies Office (White et al., 2015; White et al., 2016). The overarching goal of the DOE-led geothermal code comparison project was to learn about how the characteristics of the fractured reservoir system influenced the reservoir stimulation and fluid circulation processes at the Fenton Hill Enhanced Geothermal System (EGS) test site located in New Mexico, USA. In the code comparison study each team was tasked with developing their own conceptual model of the geological structure of Fenton Hill reservoir and then to use a reservoir simulator to model various field experiments performed at the site. We applied a coupled fluid flow, heat transfer, and geomechanics numerical model developed previously to investigate reservoir stimulation and fluid circulation efforts at Fenton Hill. For a detailed description of the numerical model used in this study, refer to McClure and Horne (2013), Norbeck et al. (2014), Norbeck and Horne (2015), Norbeck et al. (2016a,b), and Norbeck and Horne (2016a,b).

The deep Phase-II reservoir at Fenton Hill existed at a depth of roughly 3 to 4 km in fractured granitic rock (Brown et al., 2012). The geothermal system was comprised of two wells, Well EE-2 and Well EE-3. Both of these wells were eventually sidetracked to form Well EE-2A and Well EE-3A. The goal of the hydraulic stimulation treatments was to create a hydraulic connection between the two wells to allow for fluid circulation and heat extraction from the geothermal reservoir that would enable electricity generation using a small power plant located at the surface.

Norbeck et al. (2016a) investigated the hydraulic stimulation treatments performed in the Phase-II reservoir at Fenton Hill. In that study, it was hypothesized that a mixed-mechanism stimulation process, in which permeability enhancement occurred through a combination of mechanical opening of natural fractures and propagation of hydraulic splay fractures, dominated the response at Fenton Hill. Norbeck et al. (2016a) concluded that the mixed-mechanism stimulation conceptual model was consistent with several contradictory behavioral characteristics observed at the site. In the present study, we focused on understanding reservoir behavior during the two main circulation experiments performed at Fenton Hill.

In the summer of 1986, the initial fluid circulation experiments were performed. Well EE-3A served as the injection well, and Well EE-2 was the production well. The most significant circulation experiment during this period was called the Initial Closed-Loop Flow Test (ICFT). The ICFT involved two periods of relatively steady-state operation over the period of one month. For the first 15 days, the injection well was operated at a nominal wellhead pressure of 3890 psi (26.8 MPa), the production well was operated at a wellhead pressure of 350 psi (2.4 MPa), and a production rate of 3.2 BPM (8.5 L/s) was achieved (Brown et al., 2012). After 15 days, engineers decided to increase the injection rate, injection pressure, and production backpressure. A key observation was that the overall reservoir impedance was reduced (improved) at higher mean reservoir pressure. In addition, a significant amount of seismicity was observed during the ICFT.

Although fluid circulation during the ICFT was successful from a technical perspective, it was concluded that commercial circulation rates had not been achieved. Well EE-2 was sidetracked and redrilled though the microseismic cloud observed during the massive hydraulic fracture treatment. This resulted in a production well with a significantly longer section of open-hole interacting with the stimulated reservoir zone. In the summer of 1995, the second significant fluid circulation experiment was performed. This experiment was called the Long-Term Flow Test (LTFT) and consisted of roughly two months of constant circulation. Key observations during the LTFT were that the difference between injected and produced fluid volumes reduced over time, and that the reservoir accessible fluid volume grew larger while maintaining steady operation conditions (based on successive tracer tests). Electricity was generated successfully throughout this phase of circulation. The LTFT marked the final experiment performed at the Fenton Hill EGS site.

2. INITIAL CLOSED-LOOP FLOW TEST

During the first half of the ICFT, circulation was performed at relatively low injection rates and pressures. In the second half of the ICFT, the injection rate and injection pressures were raised significantly. In addition, the production well backpressure was increased during the second half of the ICFT. Important observations include that the overall reservoir impedance was reduced (improved) while operating the reservoir at relatively high mean pressure and that seismicity only occurred during injection at high pressure. The wellbore operational conditions during the ICFT phase of the simulation are shown in Fig. 1.

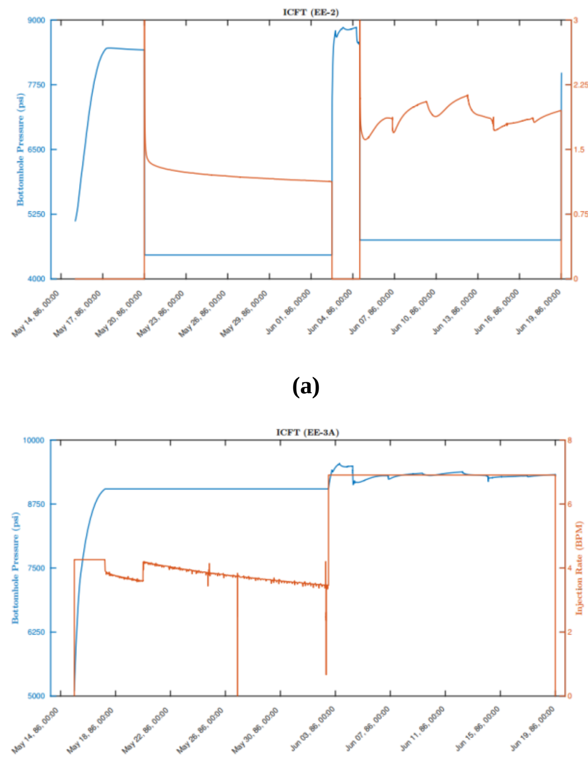
For the purposes of our analysis, we defined the reservoir impedance as:

$$I = \frac{p_i - p_p}{q_p}, \tag{1}$$

where p_i is the injection well bottomhole pressure, p_p is the production well bottomhole pressure, and q_p is the volumetric production rate. An important trait of the Fenton Hill reservoir that was recognized during the ICFT was that the reservoir impedance was affected by the mean pressure at which the reservoir was operated. Brown et al. (2012) reported a 27% reduction in impedance, and hypothesized that this behavior was caused by the ability for the fracture network to dilate at increased fluid pressure. In our model, this nonlinear behavior was able to be captured through application of a nonlinear constitutive law that related fracture conductivity and effective stress (Bandis et al., 1985; Willis-Richards et al., 1996). In Fig. 2, we show the reservoir impedance observed in the model over the duration of the ICFT. A marked reduction in reservoir impedance of 37% occurred immediately following the increase in injection pressure and production backpressure. This improved ability to circulate fluids through the reservoir was sustained throughout the remainder of the ICFT.

During the ICFT circulation experiment, a significant number of seismic events were observed. Interesting characteristics of the seismicity were that the events began to occur only after the injection pressure was increased during the second half of the experiment and that the events occurred predominantly at the edge of the region that had been stimulated previously. In Fig. 3, the locations of the modeled microseismic events are shown.

Our model matched the field behavior accurately in that seismicity did not occur until the injection pressures were increased. Furthermore, seismicity occurred predominantly at the southern edge of the stimulated zone. This behavior is intuitive, because the fluid pressures during the stimulation treatments exceeded those observed during the circulation experiments. Fractures that slipped previously were only able to slip again once they were exposed to relatively high pressure.



(a)

(b)

Figure 1: Wellbore operational conditions during the ICFT. (a) Well EE-2 was the production well, and (b) Well EE-3A was the injection well.

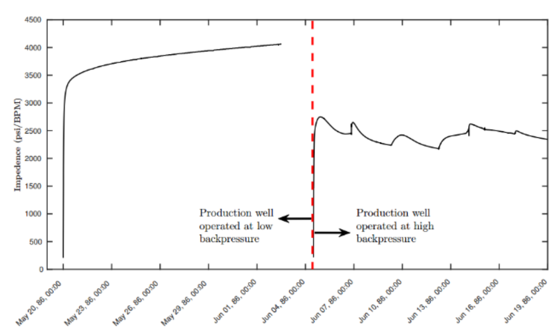


Figure 2: Reservoir impedance during the ICFT. Consistent with the observations at Fenton Hill, the reservoir impedance was improved by operating the production well at higher backpressure.

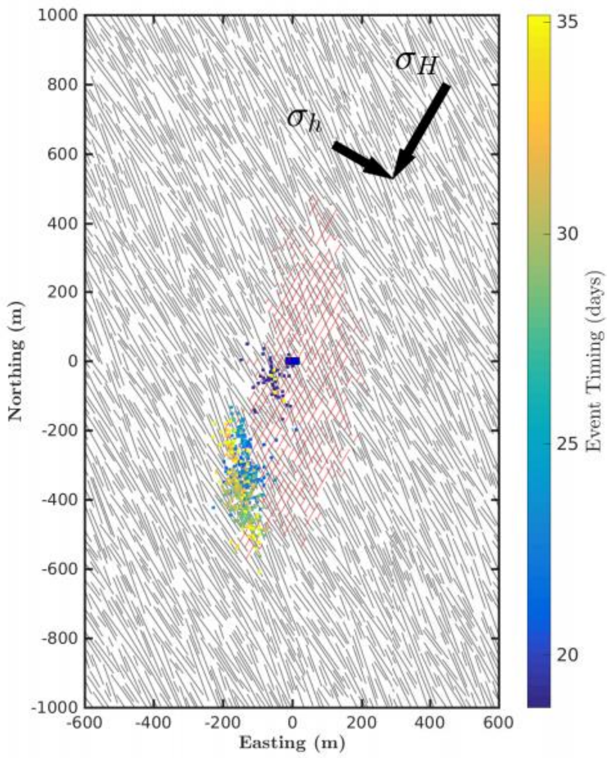


Figure 3: Microseismic event locations during the ICFT. The events are colored by timing (relative to the start of circulation).

3. LONG-TERM FLOW TEST

There were in actuality three different circulation experiments performed as part of the LTFT experiment at Fenton Hill. The first two occurred during 1992 and 1993. We did not model these two phases of circulation. Our analysis focused on the final phase of the LTFT, which occurred during May through July of 1995. Operations during the LTFT were aimed at assessing the long-term viability of the geothermal system. Well controls were maintained to minimize induced seismicity.

A trend that was observed in each of the circulation experiments at Fenton Hill was that the rate of water loss to the formation (measured as the difference between injected and produced fluid volumes) tended to decline while operating the reservoir at steady-state. The mechanism proposed by Brown et al. (2012) was that the leakoff rate into the matrix rock surrounding the fractures would decrease over time as fluid pressure in the matrix rock increased. The distribution of matrix fluid pressure at the end of two months of circulation during the LTFT is shown in Fig. 4. A significant amount of fluid leakoff into the matrix rock occurred during the simulation. In Fig. 5, we show the fractional water loss rate observed in the simulation during the LTFT. During each phase where the operational controls were maintained relatively constant, the water loss rate was observed to decline up to 10% each month. In the model, this behavior was controlled by the leakoff rate from the fractures into the surrounding rock. Our simulation results were consistent with the water loss mechanism described by Brown et al. (2012).

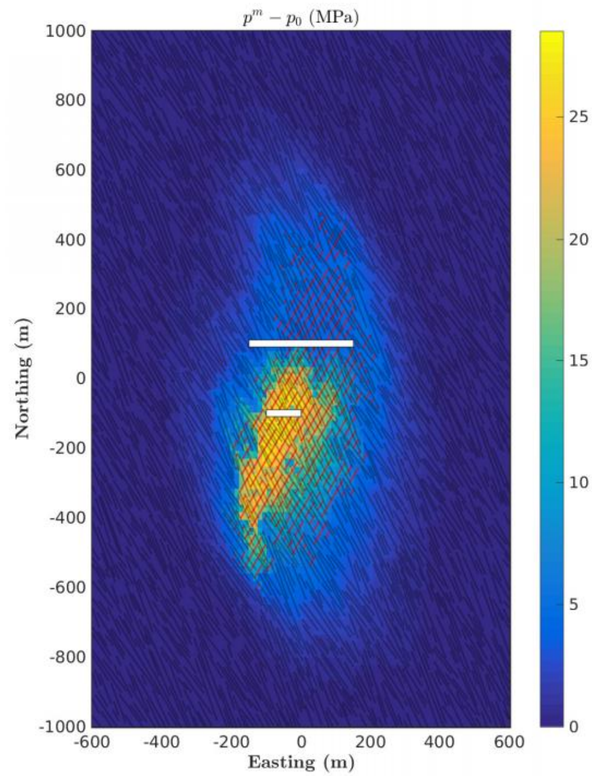


Figure 4: Matrix fluid pressure distribution at the end of the LTFT. The white lines represent the deviated wellbores.

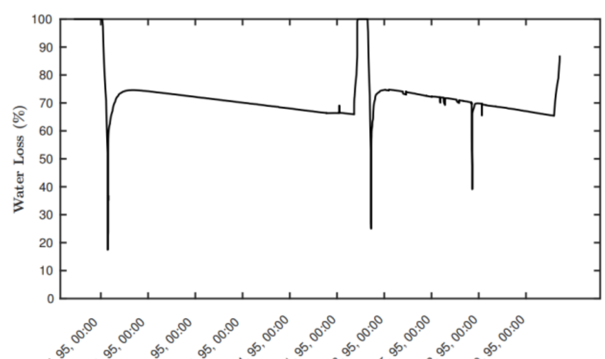


Figure 5: Difference between injection and production rate (water loss) during the LTFT. Consistent with the observations at Fenton Hill, the water loss decreased during periods of relatively constant operating conditions.

4. FRACTURE NETWORK EVOLUTION DURING FLUID CIRCULATION

The modeling results suggest that the Fenton Hill reservoir experienced nonlinear permeability changes that depended on the evolution of the state of stress throughout the reservoir. Fractures were able to dilate as the effective normal stress acting on the fractures decreased during injection. This type of deformation depended on the orientation of the fractures and was reversible. In addition, hydraulic fractures were able to propagate through the reservoir while injecting at pressures above the least principal stress. The hydraulic fractures created new flow pathways which caused an irreversible change in reservoir permeability. The overall stimulated reservoir system was comprised of both natural and hydraulic fractures, which each contributed to the reservoir response uniquely throughout different phases of reservoir operation. The evolution of the storage volume provided by the fractures as well as the connected fracture surface area throughout both the stimulation and circulation phases of the simulation is shown in Fig. 6.

In our conceptual model, the preexisting natural fractures existed pervasively throughout the reservoir at a predominant orientation of NNW-SSE and were closely spaced (Norbeck et al., 2016a). Hydraulic fractures only propagated a short distance (several tens of meters) before terminating against nearby natural fractures, and therefore provided a relatively small fraction of the connected fracture surface area as the stimulated region grew. However, the hydraulic fractures were essential to the success of the stimulation treatment because they provided the new flow connections with natural fractures that did ultimately improve the connected fracture surface area. Heat recovery from geothermal reservoirs is known to be influenced significantly by the surface area available for heat transfer to occur between the working fluid flowing though the fractures and the surrounding rock (Ames, 2016; Juliusson, 2012; Magnusdottir, 2013). The ability to recognize the functionality of different fracture sets will assist a characterization of the heat transfer surface area in EGS reservoirs.

The natural fractures were oriented oblique to the principal stresses, while the hydraulic fractures were necessarily oriented perpendicular to the least principal stress. This affected the magnitude of the normal stress acting on each of the fracture sets. The hydraulic fractures bore a lower normal stress, and were therefore able to dilate significantly at relatively low pressure. The ability for the hydraulic fractures to deform easily in the opening-mode direction allowed them to store the majority of the fluid volume in the reservoir at any given time. Brown et al. (2012) hypothesized a similar mechanism, but speculated that the two different fracture sets were both preexisting natural fractures. Our modeling results support the Brown et al. (2012) storage mechanism except for that newly formed hydraulic fracture are more consistent with other field observations.

Characterizing the fluid storage volume is important for understanding the residence time of the fluids as they circulate through the reservoir. At Fenton Hill, successive tracer tests performed during the ICFT indicated that the storage volume increased over time (see Fig. 7-12 in Brown et al. (2012)). In Fig. 1, it was observed during the ICFT that roughly doubling the injection rate only provided a modest increase in the production rate. In Fig. 6, we observe an immediate increase in the storage volume accommodated by the natural fractures in concert with the operational change. The hydraulic fractures were compliant enough to absorb most of the additional flow. Recognizing that this type of nonlinear reservoir response is possible will help to inform reservoir engineering decisions in future EGS projects.

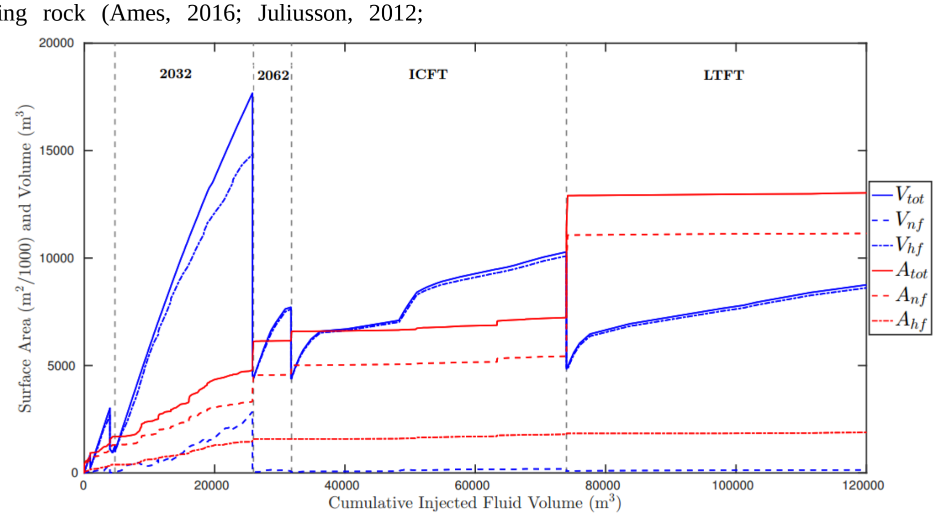


Figure 6: Evolution of the stimulated fracture surface area and stimulated fracture volume throughout each phase of the simulation shown as a function of cumulative volume of fluid injected. The red and blue solid lines represent the total fracture surface area and fracture volume, respectively. The dashed and dot-dashed lines indicate the portions associated with natural fractures and hydraulic fractures, respectively. The stimulated fracture surface area was controlled predominantly by the natural fractures, but the stimulated fracture volume was controlled by the hydraulic fractures.

5. DISCUSSION

The numerical modeling results presented in this work exhibited several distinct traits that were consistent with the behavior observed during the fluid circulation field experiments at Fenton Hill. Therefore, the modeling results provide plausible insights into the nature of how fractured subsurface systems respond to reservoir engineering operations. Understanding the fundamental physical processes that control fractured reservoir behavior has profound implications across a broad spectrum of subsurface energy fields including induced seismicity hazard, geothermal energy, unconventional oil and gas recovery, and CO_2 sequestration.

An interesting observation in the field data was that significant production rates were achieved while operating the production well at a pressure of up to 2200 psi wellhead pressure. This suggests that the bottomhole pressure was significantly higher than the initial reservoir pressure, which has important implications for understanding the hydraulic connection between the two wells. Our model results were unable to match this observation. Specifically, a realistic flow rate was only able to be achieved by operating the production well at pressures much closer to the initial reservoir pressure.

We tested other simulation scenarios (results not shown here) in which the production well was operated at pressures that were similar to the reported field data. In those simulations, fluid was not able to be produced at realistic rates. In fact, by operating the production well at pressures significantly above the initial reservoir pressure the well was forced to inject fluid. This type of behavior is obviously not consistent with the manner in which the reservoir was operated.

The implication is that the actual hydraulic connection between Well EE-3A and EE-2A must have been much stronger than in our model. The fact the fluid was able to be produced while operating at a wellhead pressure of 2200 psi suggests either a) the reservoir was naturally overpressured at depth, b) the matrix pressure had been pressurized by previous stimulation treatments, or c) the hydraulic connection between the two wells was extremely strong. There is no good evidence supporting a significant natural overpressure. Brown et al. (2012) indicated that low flow rates were maintained to pressurize the reservoir for some time around 1990, however, this was five years prior to the LTFT. Therefore, it seems likely that the two wells experienced a strong hydraulic connection involving one or more hydraulic fractures. In this way, the injection well would be able to effectively pressurize the production well sufficiently to permit significant flow rates at elevated pressures.

6. CONCLUDING REMARKS

In this work, we performed an investigation of the Fenton Hill, New Mexico, USA Enhanced Geothermal System (EGS) test site. Our goal was to develop an improved understanding of the geologic structure and hydromechanical behavior of fractured geothermal reservoirs. Using interpretations of the data sets recorded during several field experiments at Fenton Hill, we designed a conceptual model of the geologic structure and stimulation mechanism at the site. We hypothesized that stimulation (i.e., permeability enhancement) occurred though a mixed-mechanism process caused by mechanical opening of natural fractures and propagation of hydraulic splay fractures. We applied a numerical model that coupled fluid flow, heat transfer, elasticity, and fracture propagation in order to validate the hypothesis.

Norbeck et al. (2016a) demonstrated that several different independent, and sometimes seemingly contradictory, hydromechanical observations could be explained by the mixed-mechanism stimulation conceptual model. It was argued that the mixed-mechanism process may have dominated stimulation efforts at Fenton Hill. Building upon those simulations, we modeled the two main fluid circulation experiments at the site.

During the fluid circulation phase, our simulation results were consistent with the reported data in three distinct ways:

1. The overall reservoir impedance was improved by operating the production well at higher back-pressure.

2. The difference between injected and produced fluid volumes reduced over time.

3. The accessible reservoir volume grew larger over time during relatively steady operations.

The goal of the US Department of Energy Geothermal Technologies Office code comparison study was to obtain a sense of the range of conceptual models that are able to reproduce the observed data. Given that our modeling results for both the stimulation phase and the fluid circulation phase were generally consistent with the field observations, we submit these modeling results in defense of one conceptual model of the Fenton Hill EGS reservoir geologic structure and stimulation mechanism. Our model was based on several plausible assumptions (most importantly, interpretations of the state of stress at depth), which affected the simulation results significantly. We recognize that sufficient uncertainty in the state of stress is present that other models cannot be precluded.

ACKNOWLEDGEMENTS

Financial support was provided by the US Department of Energy Geothermal Technologies Office under grant number DE-EE0006646. The financial support of the industrial affiliates of the Stanford Center for Induced and Triggered Seismicity is gratefully acknowledged. The numerical simulations were performed at the Stanford Center for Computational Earth and Environmental Studies. The authors would like to thank Mark White and the participants of the US DOE GTO geothermal code comparison study for the stimulating discussions that made this study possible.

REFERENCES

Ames, M.F.: Temperature-Sensitive Tracers for Fractured Geothermal Reservoir Characterization. Ph.D. thesis, Stanford University. (2016).

Barton, N., Bandis, S., and Bakhtar, K.: Strength, deformation and conductivity coupling of rock joints. *Int. J. Rock Mech. Min. Sci. & Geomech. Abstr.*, **22**(3), 121–140, doi:10.1016/ 0148-9062(85)93227-9. (1985).

Brown, D., Duchane, D., Heiken, G., and Hriscu, V.: *Mining the Earth's Heat: Hot Dry Rock Geothermal Energy*. Springer, doi: 10.1007/978-3-540-68910-2. (2012).

Juliusson, E.: Characterization of Fractured Geothermal Reservoirs Based on Production Data. Ph.D. thesis, Stanford University. (2012).

Magnusdottir, L.: Fracture Characterization in Geothermal Reservoirs Using Time-lapse Electric Potential Data. Ph.D. thesis, Stanford University. (2013).

McClure, M. W. and Horne, R.N.: *Discrete Fracture Network Modeling of Hydraulic Stimulation: Coupling Flow and Geomechanics*. Springer Briefs in Earth Sciences, doi: 10.1007/ 978-3-319-00383-2. (2013).

Norbeck, J.H. and Horne, R.N.: Injection-triggered seismicity: an investigation of porothermoelastic effects using a rate-and-state earthquake model. In Proc., Fourtieth Workshop on Geothermal Reservoir Engineering, Stanford, California, USA. (2015).

Norbeck, J.H. and Horne, R.N.: Physical mechanisms related to microseismic-depletion delineation field tests with application to reservoir surveillance. *SPE Journal*, Preprint, 1–10, doi: 10.2118/178926-PA. (2016a).

Norbeck, J.H. and Horne, R.N.: A numerical method for fractured reservoir poromechanics using a mixed-continuum embedded fracture model. *Geothermal Resources Council Transactions*, Sacramento, California, USA. (2016b).

Norbeck, J.H., Huang, H., Podgorney, R., and Horne, R.N.: An integrated discrete fracture model for description of dynamic behavior in fractured reservoirs. In Proc., Thirty-Ninth Workshop on Geothermal Reservoir Engineering, Stanford, California, USA. (2014).

Norbeck, J.H., McClure, M.W., and Horne, R.N.: Revisiting stimulation mechanism at Fenton Hill and an investigation of the influence of fault heterogeneity on the Gutenberg-Richter b-value for rate-and-state earthquake simulations. In Proc., 41st Workshop on Geothermal Reservoir Engineering, pp. 1–22, Stanford, California, USA. (2016a).

Norbeck, J.H., McClure, M.W., Lo, J., and Horne, R.N.: An embedded fracture modeling framework for simulation of hydraulic fracturing and shear stimulation. *Computational Geosciences*, **20**(1), 1–18, doi: 10.1007/s10596-015-9543-2. (2016b).

White, M., Bahrami, D., Danko, G., Ellsworth, D., Fu, P., Furtney, J., Gao, Q., Ghassemi, A., Horne, R., Kelkar, S., McClure, M., Norbeck, J., Podgorney, R., Rutqvist, J., Sonnenthal, E., Tao, Q., Wong, Y.,, and Safari, M.: Numerical simulators for enhanced geothermal systems: GTO-CCS codes. *Computational Geosciences*, submitted. (2016).

White, S., Purohit, S., and Boyd, L.: Using GTO-Velo to facilitate communication and sharing of simulation results in support of the Geothermal Technologies Office Code Comparison Study. In Proc., Fourtieth Workshop on Geothermal Reservoir Engineering, Stanford, California, USA. (2015).

Willis-Richards, J., Watanabe, K., and Takahashi, H.: Progress toward a stochastic rock mechanics model of engineered geothermal systems. *Journal of Geophysical Research: Solid Earth*, **101**(B8), 17,481-17,496, doi:10.1029/96JB00882;doi:10.1029/9. (1996).