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Outcomes from a Collaborative Approach to a Code Comparison Study for Enhanced Geothermal Systems

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ABSTRACT

A code comparison study, supported by the U.S. Department of Energy, Geothermal Technologies Office, has recently been completed whose stated purpose was to test, diagnose differences, and demonstrate the state of modeling capabilities developed at national laboratories and academic institutes within the United States for modeling enhanced geothermal systems. This three-year study comprised two sets of problems; those classified as benchmark problems and those classified as challenge problems. The benchmark problems were structured to test the ability of the collection of numerical simulators to solve various combinations of coupled thermal, hydrologic, geomechanical, and geochemical processes. This class of problems was strictly defined in terms of properties, driving forces, initial conditions, and boundary conditions. Study participants submitted solutions to problems for which their simulation tools were deemed capable or nearly capable. Some participating codes were originally developed for EGS applications whereas some others were designed for different applications but can simulate processes similar to those in EGS. Solution submissions from both were encouraged. In some cases participants made small incremental changes to their numerical simulation codes to address specific elements of the problem, and in other cases participants submitted solutions with existing simulation tools, acknowledging the limitations of the code. The challenge problems were based on the enhanced geothermal systems research conducted in hot dry rock at Fenton Hill, near Los Alamos, New Mexico, between 1974 and 1995. The Fenton Hill Hot Dry Rock (HDR) project involved the stimulation, completion, and circulation testing in two separate reservoirs, distinguished by depth and flow complexity. Both challenge problems have specific questions to be answered via numerical simulation in three topical areas: 1) reservoir creation/stimulation, 2) reactive and passive transport, and 3) thermal recovery. Whereas the benchmark class of problems were designed to test capabilities for modeling coupled processes under strictly specified conditions, the stated objective for the challenge class of problems was to demonstrate what new understanding of the Fenton Hill experiments could be realized via the application of modern numerical simulation tools by recognized expert practitioners. Critical observations and data from the Fenton Hill experiments were varied and scattered among a number of individual experiments, and numerical simulation solutions were sought that satisfied as many observations at possible. Achieving agreement in multiple experimental observations from Fenton Hill often required participants to critically think about stimulation mechanisms involving natural and hydraulic fractures and re-evaluate their conceptual models and numerical solution approaches. This process has yielded new insights to Fenton Hill reservoirs and direction for future EGS research. The keys to the success of this study were the high quality numerical simulation tools available, the expertise of the developers and practitioners, and the collaborative approach to reporting preliminary results among the study participants. This paper describes results submitted to the challenge problems and the outcomes of a collaborative approach to conducting a code comparison study.

1. INTRODUCTION

Over the last three years, the U.S. Department of Energy, Geothermal Technologies Office has supported a code comparison study of numerical simulators for enhanced geothermal systems (EGS). The objective of this effort was to create a community forum for EGS reservoir modeling code improvement and verification, building confidence in the suite of available numerical tools, and ultimately identifying critical future development needs for the geothermal modeling community. Numerical simulation is a key method for understanding the creation and evolution of EGS reservoirs. The development of predictive numerical tools has paralleled roughly four decades of growth of EGS concepts and technology, as well as studies of other unconventional subsurface energy and geologic carbon sequestration settings. These are complex geologic environments where thermodynamics, hydrodynamics, rock mechanics, and geochemistry all contribute critically to system behavior across disparate length and time scales. The usefulness of numerical tools in these settings is moderated by confidence in the quality of the results they produce. Validation with analytical solutions, laboratory and field data, and inter-comparisons with other codes is therefore crucial to ensure that simulation can contribute robustly to EGS development. The principal issues of concern for this project were to determine 1) whether valid mathematical models for the fundamental processes associated with geothermal technologies exist, and 2) whether available numerical simulators assimilate these models to yield reliable and accurate numerical solutions to problems involving conditions of practical interest. The intent for this project was that participants with available numerical simulators were to benefit from testing and comparing their codes, diagnosing differences with other codes, and identify needs in simulation capabilities and additional research. A number of ancillary benefits were also envisioned to result from the study. Importantly, the community-driven nature encouraged broad participation and regular interaction across the numerical modeling community, promoting greater awareness and understanding of the capabilities of available tools. The result was a consortium of developers and their codes that included academic, national laboratory, industry, and international partners.

This study comprised two stages; the first (GTO-CCS Problems) (White et al., 2016b) where participants developed and addressed a series of benchmark problems, and the second (GTO-CCS Challenge Problems) where more challenging problems, extracted from real EGS field studies, were developed and considered. During the first stage of the study seven benchmark problems were chosen by the participants, with each problem having a champion. Benchmark problems were designed to investigate specific coupled processes typical of enhanced geothermal systems. This stage of the study was completed during the first year, and documented in four papers at the Fortieth Workshop on Geothermal Reservoir Engineering, held at Stanford University, Stanford, California, January 26-28, 2015 (White and Phillips, 2015; Podgorney et al., 2015; Kelkar et al., 2015; and White et al., 2015). The principal conclusions from this work were that while the U.S. EGS simulation community has a diverse set of computational tools with respect to conceptual approaches and numerical implementations, they are able to simulate coupled subsurface processes with comparable results. The evolution of numerical simulators over the last thirty-five years, since the 1980 geothermal code comparison study (Molloy et al., 1980) has been impressive, but work remains to be done. Uncertainties in simulation results as measured by the ISO-13528 standard tend to increase with the number of coupled processes in the problem and the modeling of strongly coupled THMC processes remains challenging. The collaborative nature of this study has formed the foundation for the EGS simulation community to collectively address field-scale systems, where coupled process modeling will be essential for understanding the system and experimental observations. Confidence in numerical simulation grows from agreement among field experts, especially when diverse perspectives are represented. This study yielded convergence in understanding over the course of each problem via open dialogue and discussions among the participants.

During the Challenge Problems stage of the GTO-CCS, challenge problems were developed based on the research activities conducted at the Fenton Hill Hot Dry Rock (HDR) Test Site, referred to by the Los Alamos Scientific Laboratory (LASL) (now the Los Alamos National Laboratory (LANL)) as Technical Area 57 (TA-57), or more simply as Fenton Hill (Brown et al., 2012). Fenton Hill is located about 1.9 miles west of the main ring-fracture of the Valles Caldera in the Jemez Mountains of north-central New Mexico, USA. Principal research activities at Fenton Hill took place in two HDR reservoirs. Development and testing in the Phase I Reservoir occurred between 1973 and 1980, over the approximate depth interval from 3,000 to 10,000 ft (871 to 3064 m) at temperatures between 105˚C. and 205˚C. In contrast, the Phase II Reservoir activities spanned from 1979 through 1995 at greater depths and higher temperatures, over the approximate depth interval from 12,000 to 14,000 ft (3,600 to 4,200 m) at temperatures between 260˚C and 317˚C. In terms of Holling's classification of modeling problems the GTO-CCS Challenge Problems are data rich with respect to the details about the experiments conducted at the Fenton Hill Test Site thanks to the recent publication by Brown et al. (2012), but at the same time data limited with respect the rock mass. Even critical information about the stress state in both reservoirs remain uncertain, which puts the GTO-Challenge Problems in the realm of data-limited modeling problems. Starfield and Cundall (1988) state that "the purpose of modeling data-limited problems is to gain understanding and explore potential trade-offs and alternatives, rather than to make absolute predictions." The desired outcome for the GTO-CCS Challenge Problems is that the modeling efforts yield new understanding or interpretations of the complex coupled processes that occurred during the Fenton Hill experiments, and hopefully that a collective agreement is found among the field experts often with diverse modeling approaches and capabilities. Available data sets for these problems are described in detail in White et al. (2016a).

Two challenge problems were developed; both addressing specific questions via numerical simulation in three topical areas: 1) reservoir creation/stimulation, 2) reactive and passive transport, and 3) thermal recovery. Challenge Problem #1 considers the Phase II Reservoir at Fenton Hill, located at true-vertical depths between 3,283 and 3,940 m, between wells EE-3A and EE-2A. Challenge Problem #2 considers the shallower Phase I Reservoir at Fenton Hill, located at true-vertical depths between 2,615 and 2,758 m, between wells EE-1 and GT-2B. Problem champions for Challenge Problem #1 were Derek Elsworth, Departments of Energy and Mineral Engineering and Geosciences, Penn State University, and Eric Sonnenthal, Earth Sciences Division, Lawrence Berkeley National Laboratory, and for Challenge Problem #2 were Pengcheng Fu, Atmospheric, Earth and Energy Division, Lawrence Livermore National Laboratory and George Danko, Mining Engineering Department, University of Nevada, Reno. Full problem descriptions were described by the GTO-CCS Challenge Problem champions (White et al., 2016b). Solutions to the GTO-CCS Challenge Problems in selected topical areas have been previously published (Fu et al., 2016; Norbeck et al., 2016; Mudunuru et al., 2016; and Danko et al., 2016; Gao and Ghassemi, 2016). This paper provides a synopsis of the solutions to the GTO-CCS Challenge Problems submitted during the study, both those which have been previously published and those which have yet to be published, and then provides a discussion of the outcomes of the collaborative nature of this code comparison study.

2. CHALLENGE PROBLEM #1 (FENTON HILL PHASE II RESEVOIR)

The Phase II Reservoir at the Fenton Hill test site, located near Los Alamos, New Mexico, USA, was designed to test the enhanced geothermal system concept in hot dry rock at temperatures and geothermal heat production rates near those required for a commercial electrical power plant. Phase II field activities at Fenton Hill started with the drilling of well EE-2 on April 3, 1979 and ended with reservoir circulation being discontinued on July 14, 1995, following an annular breakthrough in the injection well EE-3A. The culminating experiment at Fenton Hill was the Long-Term Flow Test (LTFT), which lasted 39 months, with 11 months of active circulation through the reservoir. The Phase II Reservoir at Fenton Hill comprised a single injection well, EE-3A and a single production well, EE-2A, which were hydraulically connected via a complex joint network in otherwise impermeable hot rock. Tracer tests conducted during the LTFT indicate, via the nature of the tracer recovery profiles during steady-flow operation periods, that reservoir fluid pathways were becoming longer over time; an indication of shorter pathways being closed off. Temperatures across the four fluid-entry points in the open-hole portion of the production well EE-2A during the LFTF show a decline in temperature over time of 7.2˚C at the deepest point and 1.8˚C at the shallowest point. Because continuous long-term circulation periods were not fully achieved within the Phase II Reservoir at Fenton Hill, there remains uncertainty about the thermal recovery performance of the reservoir over an extended period of time.

This problem seeks solutions via numerical simulation that answers specific questions concerning the Phase II Reservoir at Fenton Hill, in three topical areas: 1) reservoir creation/stimulation, 2) reactive and passive transport, and 3) thermal recovery. The response of the Phase II Reservoir to fluid injection and production is considered to be governed by strongly coupled hydrologic, thermal, geomechanical, and geochemical processes. Solutions shall address the coupled nature of these processes and demonstrate consistency with the experimental observations made during the reservoir creation and circulation tests as part of the Phase II Project at Fenton Hill. Models of the hydraulic connection between wells EE-3A and EE-2A can be conceptual or fracture networks generated via numerical simulation of the Phase II reservoir development via the hydraulic stimulation. Within the descriptions of each of the three topical areas, problem statements will include a question, metrics, and output section. The metrics section includes key experimental observations made during the Phase II Project at Fenton Hill, but the study encouraged solution submissions that utilized additional metrics to demonstrate coupled processes or defend submitted solutions.

2.1 University of Nevada, Reno

The team from University of Nevada, Reno (UNR) developed a new fracture and flow system modeling methodology (Danko et al., 2016) and applied this methodology to elements of the reactive-transport and thermal recovery topical areas of Challenge Problem #1. Their approach involved developing a network of elliptical planar fractures that connected injection well EE-3A with the production well EE-2, using the three-point location method of clustering the micro-earthquakes. The resulting network comprised 10 fractures with centroids, orientations, and dimensions (i.e., major and minor radii) with the centroid locations and sizes adjusted to match published connectivity by Smith (Smith et al., 1989). The fracture planes were then discretized with structured rectangular meshes, allowing for variable aperture across the fracture extent. Principal assumptions of the analysis were isothermal conditions and constant fracture aperture, with reference fracture aperture and pressure aperture coefficient being principal unknowns, determined by executing the fracture network flow model against two stages of the fluid circulation tests, as reported by Duchane (1996). The dynamic behavior of the fracture network to the production well back pressure was demonstrated, by fracture apertures of 0.094 and 0.103 mm, respectively for production pressures of 9.7 and 15.2 MPa. One principal outcome from this solution submission was that calibration against the experimental circulation flow tests was possible with a simple aperture fracture network model with just two parameters. The UNR team additionally concluded that incorporation of variable fracture aperture and thermal contraction would allow the fracture flow model to predict thermal drawdown, the core question in the thermal recovery topical area for Challenge Problem #1.

2.2 Pennsylvania State University

The team from Pennsylvania State University (PSU) utilized a new numerical simulator, TF_FLAC^{3D}, for modeling a randomly distributed fractured rock mass *via* an equivalent continuum approach (Gan and Elsworth, 2016). This new modeling approach advances the PSU team's capabilities for EGS reservoirs, building on their previous continuum simulator TFREACT (Taron et al., 2009). The key advancement was the ability to model fracture networks within an EGS reservoir without gridding dependence, with the implementation of constitutive equations for stress-dependent permeability, including normal closure, shear dilation, and out-of-contact fracture walls under tensile loading. The critical elements of this development were the mapping of discrete fractures onto a discretized 3-dimensional rock mass volume, the formulation of an equivalent continuum Young's modulus and Poisson ratio, a permeability tensor, a porosity model, and a model for stress-dependent fracture aperture, and the development of an iterative solution scheme to realize convergence. The PSU team demonstrated this new modeling capability against single- and multi-fracture validation problems, with the single-fracture problem being Benchmark Problem # 6: Injection into a fault/fracture in thermo-poroelastic rock. Whereas the equivalent continuum approach adopted by the PSU team differs from the embedded fracture model approach of the Stanford team in terms requiring additional spatial discretizations to account for the fractures, both approaches recognize the need for modeling discontinuous fracture networks with variable fracture dimensions and orientations.

The PSU team approach to answering the thermal recovery topical area question of Challenge Problem #1 was two staged. During the first stage, fracture networks of the Phase II reservoir were defined from the seismic events recorded during the injection phase of the massive hydraulic fracturing (MHF) Test (Roff et al., 1996), conducted at Fenton Hill and known as Experiment 2032. Fracture networks were developed from the major fault plane orientations reported by Phillips et al. (1997) (i.e., near vertical at -56˚ / 70˚), using an assumption of 1 fracture in each direction per cluster of 20 seismic events. This resulted in a network with 190 fractures in each of the two principal directions. Fractures lengths were assumed to be normally distributed with a mean of 50 m / 30 m and standard deviation of 20 m / 10 m. Simulations of the 2 ½-day MHF Test were then executed with the developed fracture network, using the recently developed TF-FLAC^{3D} simulator. Pressure distributions were generated after 3 days of injection at constant rate of 0.1 m^3/s, approximating the rate of the MHF Test for two presumed principal horizontal stress realizations, oriented 0˚ / 90˚, of 40 MPa / 25 MPa and 20 MPa / 13 MPa. The objectives for this stage of the study was to develop a fracture network and fracture properties that yielded agreement with the pressure response of the MHF Test, given the stress state and fluid injection rate.

During the second stage of the study, the PSU team examined the response of two different closed fracture networks; a sparse long fracture network based on a single fracture in each major fault plane orientation reported by Phillips et al. (1997) (i.e., near vertical at -56˚ / 70˚) per cluster of 80 seismic events with average lengths of 300 m / 200 m, and a dense short fracture network with a single fracture in each direction of average lengths 70 m / 30 m per cluster of 30 seismic events. Simulations were then executed based on the flow rates of the Initial Closed-Loop Flow Test (ICFT) (Brown et al., 2012), for a period of ten years using the sparse-long and dense-short fracture networks, and two reservoir thicknesses of 50 m / 200 m. An observation from the Fenton Hill project was that a second production well on the stagnant end of the elongated reservoir would be beneficial in terms increasing productivity. The PSU team's dual production well configuration followed this recommendation. Simulation results revealed significant differences between the thermal recovery in terms of power and total energy between the sparse-long and dense-short fracture networks, with the dense-short networks achieving roughly 2.75 times the total recovered energy compared with the sparse-long networks. The case for a 200m thick reservoir returned ~20% higher production rate and a longer thermal life than the 50m reservoir (for the same mass flow-rate). Stress changes at the end of the 10-year production period in the three principal directions due to thermal contraction and fluid injection were large, yielding fracture permeability increases and potentially tensile opening of some fractures. The solution submission from PSU provided a new perspective on the performance potential of the Fenton Hill Phase II reservoir, which predicted that >20MW$_{th}$ and >7MW$_{th}$ systems can be operated for initial periods for the dense-short and sparse-long fracture networks. Long term thermal recovery predictions are in general agreement with simulation predictions of 4 MW$_{th}$ production over a 30-yr period, but the PSU simulations show more intensive initial production with moderately sharp thermal drawdown after several years. The thermal drawdown behavior is strongly dependent on reservoir thickness. For the 50-m reservoir, strong thermal drawdown occurs after the 2nd year while for the 200-m reservoir the lifetime is approximately three-times longer. Extrapolating the simulations results to 30 years, shows thermal power production falling below 1 MW$_{th}$ around 15 years for both the dense-short and sparse-long fracture networks for the 50-m reservoir thickness. In terms of the objectives of the GTO-CCS Challenge Problem stage, the PSU team recognized the need for modeling fracture networks of random orientations and dimensions, with fracture permeability being stress dependent, including normal closure, shear dilation, and out-of-contact fracture walls under tensile loading and then advanced their simulation capabilities in response.

2.3 Los Alamos National Laboratory

The team from Los Alamos National Laboratory (LANL) approached the challenge of predicting the long-term thermal recovery performance of the Fenton Hill Phase II Reservoir from a reduced-order modeling approach (Mudunuru et al., 2016). The founding concept behind reduced order modeling is to develop functions of a limited parameter set that describe the behavior of a complex system. Generally the parameter sets and functional forms are chosen, and the function coefficients are determined from numerical simulations executed with conventional coupled-process models on the complex system. For this work the LANL team used the PFLOTRAN (Lichtner et al., 2015) simulator to model fluid flow and heat transport within the Phase II Reservoir. For this analysis the team elected to not consider geomechanical or geochemical effects on the system. The geologic model of the Phase II Reservoir assumed 1000 m x 1000 m x 1000 m rectangular reservoir, with an embedded 650 m x 650 m x 500 m rectangular fracture zone, and both zones having constant density, specific heat, thermal conductivity, and intrinsic permeability. The conceptual model of the Phase II Reservoir included a vertical injection and production well, intersecting the fracture zone, with constant fluid heat capacity, fluid density and fluid injection temperature. The parameter set for the reduced-order model comprised the fracture-zone permeability, production-well skin factor, injection mass flow rate, and bottom-hole pressure. Three reduced-order models were considered to predict the thermal power output from the Phase II Reservoir over a 120-day time period, within the LTFT experiment at Fenton Hill (Brown et al., 2012), using time and fracture-zone permeability as the parameters. Reduced-order models that included the production-well-skin-factor, injection-mass-flow-rate and bottom-hole-pressure parameters were not developed. Estimates of thermal power production for the Phase II Reservoir from the reduced-order models for time periods up to 20 years beyond the LTFT were reserved for future work. An outcome from this solution submission with respect to the objectives of the GTO-CCS Challenge Problem stage was the adaptation of the reduced-order model approach to EGS. Whereas the submitted solution developed reduced-order models for thermal power production solely based on time and a single reservoir parameter, the implementation an expanded parameter set, and inclusion of geomechanical and geochemical effects will reveal the true potential of applying reduced-order models to EGS operations.

2.4 McClure Geomechanics LLC and Stanford University

The teams from McClure Geomechanics LLC and Stanford University (McCG-Stanford) collaborated to investigate: (1) the hydromechanical behavior during stimulation and (2) the thermal drawdown during long-term circulation. The analysis is described in detail by Norbeck et al. (2016a) and Norbeck (2016). Modeling was performed using the two-dimensional version of CFRAC (Complex Fracturing ReseArch Code), a discrete fracture network simulator that couples fluid flow with the stresses induced by fracture deformation and porothermoelastic deformation in the matrix. Detailed descriptions of the numerical formulation for the model used in this study are provided in Norbeck et al. (2016b) and Norbeck and Horne (2016).

The interpretation of the hydromechanical behavior was based on the following observations: (1) injectivity increased very sharply and nonlinearly at a threshold bottomhole pressure (BHP); (2) at BHP less than the threshold pressure, injectivity was low and did not increase significantly from one injection sequence to the next; and (3) the microseismic cloud formed an ellipsoidal region with the long axis nearly north-south (with a slight rotation to the west), very different from the direction of the maximum principal stress (N30˚E). The orientation of the stresses is known from the orientation of breakouts in acoustic borehole televiewer logs. According to conventional geomechanical theory (Zoback, 2007), observation (1) suggests that hydraulic fractures formed and propagated through the formation. Observation (2) suggests that shear stimulation caused minor or negligible increase in injectivity. Observation (3) is seemingly contradictory with observation (1) because in the far-field, hydraulic fractures form perpendicular to the minimum principal stress. The long axis of the ellipse should form in the direction perpendicular to the minimum principal stress; the shorter axis of the microseismic cloud forms as fluid leaks off from the hydraulic fracture into the surrounding formation, triggering microseismicity.

The McCG-Stanford team focused on reconciling the contradiction between observations (1) and (3). Three hypotheses were considered: (a) the orientation of the maximum principal stress was not actually N30˚E; hydraulic fractures formed at the well and propagated perpendicular to the (true) minimum principal stress; the long axis of the microseismic cloud is, in fact, in the direction of maximum horizontal stress; (b) at the well, hydraulic fractures formed at the well and propagated through the formation perpendicular to the minimum principal stress; away from the well, they intersected large, permeable fault zones; subsequently, fluid flow occurred dominantly down the faults, causing the microseismic cloud to orient in the direction of the strike of the large faults; (c) stimulation occurred through the 'mixed mechanism' conceptual model described by McClure and Horne (2013; 2014); hydraulic fractures were unable to form at the wells because of the high tensile strength of the granitic rock; the threshold BHP corresponded to the normal stress on the natural fractures in the formation that intersect the well, which were jacked open; hydraulic fractures were able to form as splays off the natural fractures or from extension from the tip; the hydraulic fractures terminated against natural fractures due to mechanical interaction; the overall result was a mesh of hydraulic fractures perpendicular to the minimum principal stress and natural fractures oriented at (roughly) N23˚W, which led to an overall north-south orientation of the stimulated region.

Hypothesis (a) cannot be entirely ruled out. However, the orientation of the horizontal stresses is known from interpretation of wellbore image logs, which is a highly reliable technique for estimating stress orientation. The orientation could only be incorrect if there was an error during the acquisition of the image log data. Hypothesis (b) seems unlikely because there is no evidence of large, highly permeable faults in the Fenton Hill reservoir. The injectivity of all wells was low, indicating that none intersected a highly permeable fault. Large faults form thick damage zone with characteristic formation of cataclasite and other features, none of which were reported from any core or cuttings collected at the site. Large-scale permeable faults cause convective temperature gradients (low thermal gradient); high thermal gradients were observed at depths at Fenton Hill. The microseismic cloud extended about the same distance from the injection well in both directions, and so hypothesis (b) requires that there were at least two parallel large-scale faults present in the formation, with the injection well coincidentally located midway between them.

Hypothesis (c) is similar to the theory proposed by Brown (1989) and Brown et al. (2012), where the reservoir consisted of two sets of joints – one perpendicular to the minimum principal stress (storing the majority of the injected fluid) and another joint set at a different orientation, bearing significantly higher normal stress. Hypothesis (c) modifies this theory by asserting that the fractures perpendicular to the minimum principal stress were not natural fractures, but instead were generated during the injection and propagated from the mechanically opened natural fractures. Termination of hydraulic fractures against natural fractures is a necessary feature of the hypothesis because otherwise, the hydraulic fractures, once formed, would propagate perpendicular to the minimum principal stress and cause the overall microseismic cloud to orient in their direction of propagation. At the time of the Fenton Hill project, the concept that hydraulic fractures may terminate against natural fractures was not widely recognized in the literature; therefore, it is unsurprising that this mechanism was not considered by Brown (1989). But today, fracture termination against preexisting features is widely recognized as a potentially significant process and is an area of active research (summarized by McClure and Horne, 2014). Hypothesis (c) deviates from conventional geomechanics theory (Zoback, 2007) in asserting that fluid pressure exceeded the minimum principal stress at the well and did not induce hydraulic fracture propagation directly from the well. However, Section 4.8 from Norbeck (2016) lists several field examples of high rate injection into granite where this has occurred. It is hypothesized that in very high strength rocks such as granite, tensile strength for fracture initiation becomes non-negligible.

Hypothesis (c) implies the minimum principal stress is much lower than implied by Hypotheses (a) and (b). In fact, a discrepancy was noted in the data at the site. Shallower measurements indicated a low stress gradient, while deeper measurements seemed to indicate a much higher stress gradient. Kelkar et al. (1986) interpreted these measurements as indicating a large discontinuity in the stress state at around 3 km depth. Brown (1989) proposed that the lower stress profiled prevailed throughout and that there was a discontinuity in the natural joint orientation at 3 km depth. A mix of strike-slip (SS) and normal faulting (NF) focal mechanisms of the seismic events indicated a transitional SS-NF stress regime with $S_v \cong S_h^{max} > S_h^{min}$. The low-stress-gradient model is what one would expect, given constraints on stress magnitudes, following the assumption of a critically-stressed crust (Zoback, 2007). Conversely, the high-stress-gradient model would require a pure SS stress regime (i.e., $S_h^{max} > S_v > S_h^{min}$) to be consistent with the critically stressed crust assumption at the 3.6 km depth.

Using Hypothesis (c) and the lower stress profile proposed by Brown (1989), the entire injection, shut-in, and flowback history into the Phase II wells (during the stimulation phase) was simulated with CFRAC in a reservoir-scale discrete fracture network in a single continuous simulation (spanning nearly two years). The simulations involved propagation of hydraulic fractures as splays off natural fractures, and the propagating fractures subsequently terminated against other natural fractures. The simulation results were consistent with the overall observations – orientation of microseismic cloud and a threshold pressure for mechanical opening of natural fractures (Norbeck et al., 2016). In order to match the observation that injectivity below the threshold pressure did not increase significantly between injections, it was necessary to specify in the simulation settings that shear stimulation had minor or zero effect. The simulations reproduced the occurrence of the Kaiser effect in subsequent injections and the rate of spreading of microseismicity from the wellbore. Simulations with and without poroelastic and thermoelastic effects were performed.

Next, the simulations were extended to include the several circulation tests that were performed in the reservoir. The simulations were consistent with the spatial and temporal distribution of seismicity that occurred during circulation and consistent with the observation that seismicity only occurred when injection pressure was increased. The simulations were also consistent with the data in showing a drop in reservoir impedance when backpressure was increased at the production well and that there was a decline in water loss to the formation over time. One area of mismatch was that the simulations required bottomhole pressure to be near the in-situ reservoir pressure in order to match the observed production rate. In the real data, significant production rates were accomplished with bottomhole pressure much greater than the in-situ reservoir pressure. This remarkable observation can only be explained by positing that there was a strong hydraulic connection between the production and the injection wells. In the simulation, the connection between the wells was affected by the randomness of the discrete fracture network; in the particular simulation run for the study, there as not (by chance) a strong connection. In the Fenton Hill project, the wells were sidetracked and redrilled several times until a good connection was achieved, indicating that the connection observed in the actual data was dependent on fortunate alignment of the wells along a high conductivity fracture.

The conventional theory of EGS stimulation is that injection induces significant shear stimulation. While there is uncertainty between hypotheses (a), (b), and (c), the McCG-Stanford concludes that the data does not support the hypothesis that shear stimulation was the dominant factor in the hydromechanical response of the wells during the injections studied in Challenge Problem #1.

3. PROBLEM #2 (FENTON HILL PHASE I RESEVOIR)

The Phase I Reservoir at the Fenton Hill test site, located near Los Alamos, New Mexico, USA, was designed to demonstrate the technical feasibility of the enhanced geothermal system concept in hot dry rock. Phase I field activities at Fenton Hill started with the drilling of the GT-2 borehole on February 17, 1974, and ended with the shutdown of final circulation on December 16, 1980. Various tests, including injection and flow-back experiments, well logging and coring, chemical tracer and chemical leaching were performed concurrently with the drilling program. After the establishments of hydraulic connections between the two wells, a series of five circulation tests, referred to as Run Segments 1-5, were conducted in the Phase I Reservoir. Heat was produced from two different stimulated fractures/fracture networks in Run Segments 1-3 and in 4-5. A full set of evidences suggest that the sub-reservoir producing heat in Run Segments 1-3 consists of a major fracture intersecting Well EE-1 at 9050-ft (2758-m) depth and Well GT-1B at 8769-ft (2673-m) depth. The majority of the circulated fluid entered into the major fracture via the intersection with Well EE-1 and exited from the fracture through the intersection with Well GT-2B. Temperature logs along the wellbore indicated that the flow entry points at 8620 ft (2627 m) and 8900 ft (2713 m) in Well GT-2B also contributed to the flow. The hydraulic impedance of the producing reservoir was very low, especially when a high backpressure was applied to dilate the fracture. The fracture that produced heat during Run Segments 1-3 was of modest size and substantial thermal drawdown had taken place. The sub-reservoir responsible for Run Segments 4 and 5 was of a much larger volume and only limited thermal drawdown evolved during the 9-month Run Segment 5 circulation. However, the high hydraulic impedance and its insensitivity to backpressure suggested that the reservoir was likely composed of multiple intersecting fractures under high confining stresses. However the available evidence was insufficient to constrain a definite fracture network model. Challenge Problem #2 seeks solutions via numerical simulation that answer specific questions concerning the Phase I Reservoir at Fenton Hill, in three topical areas: 1) reservoir creation/stimulation, 2) reactive and passive transport, and 3) thermal recovery.

At this writing four teams have submitted solutions against the Reservoir Creation and Stimulation topical area of Challenge Problem #2 while no systematic analysis of the other two components of the problem was presented, likely due to the limited time and resources that the teams had. The Reservoir Creation and Stimulation component concerns a series of five pressurization and venting experiments in Zone 7 of well GT-2 after stage 2 drilling of Fenton Hill Phase I, performed in September 1974. These experiments provided intriguing field observations that make it possible to infer the hydraulic stimulation mechanism involved. Zone 7 is the open-hole interval at the bottom of well GT-2 after stage 2 drilling (2043 m deep). Field observations indicated that two natural joints between 1990-1993 m and 1999-2000 m deep, respectively, approximately dipping 70˚, might have been opened by the stimulation. Key observations from the five injection, shut-in and subsequent venting experiments included the following: 1) pressure limiting behavior -- injectivity rapidly increased once the wellhead pressure reached 17.2 MPa (2500 psi); 2) shut-in pressure declined after the first injection exercises, as depicted in Figure 3-9 of Brown et al. (2012); 3) there was small flow-back ratio of the injected water after the first four water injection experiments; and 4) there was very high fluid recovery ratio after the fifth injection, which used cross-linked gel mixed with sand. Each participating team was asked to simulate these injection, shut-in, and flow back operations, using assumptions consistent with conditions reported in Brown et al. (2012) and other Fenton Hill related publication, with the objective of reproducing these field observations and offering insight into the associated stimulation mechanisms.

3.1 Problem Refinement via Group Discussions

The definition of the problem was refined, mostly in the form of clarifications on field observations and physics that needed to be incorporated, based on discussions among the teams tackling this problem, consulting with key participants in the original Fenton Hill study, and preliminary simulations by the problem champion and interested teams.

A complication in the interpretation of the fifth test (gel injection with proppant), discovered by Mark McClure, was that a simple volumetric analysis generated some uncertainty about whether proppant actually entered the formation. Based on the well completion dimensions of well GT-2, as shown in Figure 3-8 (Brown et al., 2012), the wellbore volume was around 21-25 m^3. However, during the proppant injection period, only 17 m^3 of fluid were injected. This simple volumetric analysis suggested that gel-proppant mix could not have displaced all the fluid in the wellbore allowing it to enter the formation/fracture.

Don Brown (personal communication with Mark McClure) indicated that there was field evidence to support proppant having entered the formation because the injection pressure sharply increased by several 10s of psi a few minutes before shut-in. An interim solution that allowed the participants to proceed with their model building while the problem was further investigated was to assume that because the proppant is denser than water, it settled downward through the well faster than the fluid being pumped. An explanation that McClure worked out and most participants found to be convincing was that the more viscous gel tends to only displace the less viscous water near the center of the wellbore due to mechanisms presented in Tehrani (1996). Therefore, the gel only needed to displace a fraction of the water in the wellbore to enter the formation, so the interim assumption was appropriate and did not have a negative impact on the resultant simulations.

Some participants raised questions regarding the potential role thermal stress could have played in the five injections tests. The problem champion simulated heat exchange between the injection fluid and the wellbore, cooling of the rock surrounding the fracture, and thermal stress caused by the cooling using a THM coupled model based on LLNL's GEOS code. The results show that great tensile stress (up to 50 MPa tensile stress increment) could develop due to the cooling; this stress component is parallel to the fracture plane and is constrained within a small distance from the fracture. This could have resulted in many short, parallel fractures perpendicular to the fracture plane but such thermal fracturing does not contribute to the four phenomena that we tried to investigate. The thermal stress perpendicular to the fracture plane is approximately 1.3 MPa, a small fraction of the *in situ* stress.

3.2 McClure Geomechanics LLC

McClure Geomechanics LLC (McCG) simulated Challenge Problem #2 with the 3D version of CFRAC, which includes proppant transport and fracture closure onto the proppant placed in the fracture (Shiozawa and McClure, 2016). The results were summarized by Fu et al. (2016). The entire sequence of five injections over several days (with either flowback or shut-in between the injections) was modeled in a single continuous simulation. All five injections showed a consistent threshold bottomhole pressure at which injectivity transitioned from being very low to very high. This is interpreted as indicating mechanical opening of a fracture – either a natural fracture or a newly forming hydraulic fracture. In the simulations, it was assumed that there was a single preexisting fracture normal to the minimum principal stress. For the purposes of matching the data in Challenge Problem #2, the exact orientation of the natural fracture and the stress state is non-unique – all that matters is that the normal stress on the fracture is consistent with the observed threshold pressure for jacking. The model assumed that injection occurred at a specific depth point on the well – as if a fracture was intersecting the vertical well obliquely. If the model had assumed an axial vertical hydraulic fracture formed, this may have had some effect on the results.

If the fracture were not perpendicular to the minimum principal stress, then it would have slide in response to injection. However, the data indicated that there was low injectivity prior to reaching the threshold BHP in all five injections. This implies that shear stimulation was minor or negligible and that mechanical opening dominated the hydromechanical behavior (whether or not significant fracture shear occurred). This interpretation is consistent with the interpretation presented in Section 2.4 for the Phase II reservoir. It should be noted that shear stimulation has been widely accepted in the EGS community as being the primary control on hydromechanical behavior during stimulation, yet in both Challenge-Problem datasets, McCG and Stanford interpret that fracture mechanical opening is the dominant process, compared to shear stimulation. These observations are consistent with the theory of McClure and Horne (2014), who proposed that shear stimulation is the dominant mechanism only in formations with large, preexisting, high permeability faults (which arguably constitute the minority of historical EGS projects).

Simulation parameters were varied to match the pressure transient trend during shut-in after the initial injection period. The transient was controlled by two parameters affecting the magnitude and effective stress sensitivity of the aperture when the fracture is mechanically closed. These parameters were varied until a very close match to the transient was achieved. Because of the uncertainty about whether proppant entered the formation during the final injection period, two simulations were performed. In the first, it was assumed that no proppant entered the formation. In the second, the full proppant transport and fracture closure algorithm developed by Shiozawa and McClure (2016) was implemented to capture the placement of proppant during the final injection.

The simulation without proppant indicated a much higher fluid recovery after the fifth injection than after the previous injections. Significantly, this occurred without either shear stimulation or proppant entering the formation. Prior to the fifth injection, each injection was performed with greater volume and duration than the previous, causing stimulation to extend further and further from the well and allowing more time for leakoff (both factors reduced fluid recovery). A large volume of fluid leaked off from the fracture during the previous injections, pressurizing the surrounding matrix and reducing leakoff rate in subsequent injections. The fifth injection used a much smaller volume of fluid and shorter injection duration than the previous injections. These factors, and the pressurization of the surrounding matrix during the previous injections, resulted in much higher fluid recovery after the fifth injection.

In the simulation with proppant, the proppant was placed into a roughly radial region around the injection point. After closure, the proppant greatly increased fracture conductivity and significantly increased fluid recovery. McCG concludes that the greater fluid recovery in the fifth injection is due to the smaller injection volume, the pressurization of the surrounding matrix during the previous injections, and probably (though not necessarily) proppant entering the formation.

The interpretation from McCG differs from some other groups in finding that the observations cannot be explained by the hypothesis that there was shear stimulation or any other irreversible change in the hydromechanical properties of the fracture as a consequence of injection. It is not known whether or not injection induced slip (this depends on the unknown orientation of the fracture inferred to be intersecting the well). If injection did induce slip, then (because of the Kaiser effect) the slip would have occurred during the earlier injection periods and not during the (lower volume) final injection. The same argument applies to any other irreversible process for changing the fracture conductivity; if fracture conductivity changed irreversibly in response to injection, this would have already occurred during the first four injections. Yet fluid recovery was high only after the final injection. There is laboratory evidence to suggest that cycling of open/closing causes hysteretic change in fracture conductivity, but the evidence indicates that cycling causes conductivity to decrease, not increase, due to wear of asperities (Barton et al., 1985). If anything, this effect would have decreased, not increased, fluid recovery in the final injection.

It cannot be ruled out that there were irreversible changes in fracture properties, but these processes cannot explain why recovery was much higher in the final injection. If they occurred, the data suggests that they were secondary effects relative to the dominant effect of mechanical opening of the fracture when pressure reached its normal stress. McClure et al. (2014) discussed the experiment in Challenge Problem #2 and hypothesized that the fluid recovery was affected by propagation of splay fractures from an obliquely oriented natural fracture that was opened at the wellbore (similar to the conceptual model used in Section 2.4 of this manuscript). While the findings in this section do not rule out this mechanism, they indicate that it is not necessary to explain the observations; more parsimonious explanations are possible.

3.3 Lawrence Livermore National Laboratory

Although LLNL's model was also based on an explicit representation of the fracture(s), similar to McClure Geomechanics LLC's approach, GEOS and CFRAC are based on very different numerical methods: finite-element method + finite-volume method (FEM+FVM) vs. boundary-element method + finite-volume method (BEM-FVM). LLNL's modeling assumed that a large vertical fracture plane, 800 m X 800 m in size, centered at the wellbore intersection is embedded in the impermeable rock body. The fluid viscosity was assumed to be 1 cP for the first four tests, and 10 cP for Test 5. Proppant transport was not explicitly simulated; instead, we assumed a "propped" zone, 20 m in radius around the injection point, loosely based on the proppant simulation results of the McClure team. The fracture aperture in this zone was assumed to be not smaller than 30% of the maximum aperture experienced by the corresponding area during the fluid injection. At the commencement of a venting stage following injection, a pressure boundary condition was applied at the intersection between the fracture and the wellbore, forcing the fluid pressure to linearly decrease from the shut-in pressure to the hydrostatic pressure in five minutes and remain at hydrostatic thereafter.

LLNL's simulations of Tests 1 though 4 showed a strong tendency of the injected fluid to migrate upwards once it enters the fracture from the wellbore. This is mainly due to the fact that the vertical gradient of the closure stress on the fracture is much greater than the hydrostatic gradient. Consequently, the fluid continued to move upwards along the fracture during venting instead of flowing downwards to the wellbore. Additionally, the near-wellbore aperture during venting is very small due to the low effective stress near the wellbore during venting (i.e. the near-wellbore region of the fracture is choked), which also prevented fast flow-back. In the simulation of Test 5 where gel and proppants were used, high fluid viscosity remarkably impedes the upward tendency of the fluid migration. The aperture near the wellbore was dilated to at least 3 mm during injection. Such a large aperture allowed the proppant to enter the fracture, which in turn retained a relatively large aperture during venting. The combined effect of these two factors, namely fluid staying near the wellbore and smaller near-wellbore impedance, results in very high (considerably higher than the injection rate) flow-back rate in the beginning of the venting. The simulation results show that less than 3% of the fluid flowed back in each of the first four tests whereas more than 80% of the injected fluid flowed back in Test 5. LLNL's simulations are highly consistent with the field observations and offer insight into simple yet definitive mechanisms behind the observations.

A detailed comparison between McClure Geomechanics LLC's model and LLNL's model in terms of simulation approach and results has been presented in Fu et al. (2016). Despite their similarity in that fluid was injected into a pre-existing natural fracture, the two teams' models are substantially different from each other in a number of aspect such as numerical approaches, assumptions on fluid viscosity, and assumed dimensions of the fractures. However, both sets of models capture the most important field observations, including the shut-in pressure behavior and the fluid recovery ratios for different injection scenarios quite well. This modeling exercise proves a natural fracture(s) having been opened during the stimulation is a plausible hypothesis.

3.3 The University of Oklahoma

The team from The University of Oklahoma (OU) applied numerical simulators, developed by the faculty and students from the OU Mewbourne School of Petroleum and Geological Engineering for addressing problems involving coupled thermal-hydrological-mechanical processes for three-dimensional geologic domains, such as nuclear waste repositories, petroleum reservoirs, and enhanced geothermal systems, in an innovative fashion to the Phase I Reservoir at Fenton Hill. The OU developed simulators solve fully coupled equations for three-dimensional geomechanics, heat transport, and saturated fluid flow using finite-element spatial discretization with hexahedral shaped elements, having eight nodes per element. This formulation results in five unknowns per node; displacements in the three principal directions, pore fluid pressure, and temperature. For the Fenton Hill application fractures were assumed to be pre-existing and were explicitly modeled as elements within the finite-element grid, with the element having a width much larger than the fracture aperture. The OU team verified this numerical simulator against the Terzaghi one-dimensional consolidation problem, for which there is an analytical solution (Francesco, 2013). Agreement was additionally shown for a nonisothermal consolidation against solutions published by Noorishad et al. (1984). A key element of the OU numerical simulator is the continuum damage approach (Lee and Ghassemi, 2009) taken to model the joint reactivation or failure process.

The OU team chose to address experiments conducted during late September, 1974 within the Phase I reservoir at Fenton Hill, involving a series of 5 reservoir stimulation injections of water into the open borehole section of well GT-2 between depths of 1981 to 2043 m (6498 to 6702 ft), known as Zone 7. The first injection being one of short duration (i.e., 1 minute) and the final injection including a cross-linked polymer and sand proppant. Joint parameters and grid sensitivity were determined from comparison simulations completed against the first stimulation test, including a zero stress aperture of 100 μm, a joint stiffness parameter (α) of 200, effective normal stress at an [$\alpha /(\alpha +1)$] reduction in aperture of 10 MPa, and a residual aperture of 0.1 μm. For grid sensitivity, 10- and 5-m sized fracture elements were considered. With these parameters good agreement between the joint opening pressure and the pressure decay profile were noted for a minimum horizontal stress of 34 MPa. The four remaining injection experiments were modeled via three approaches: 1) constant joint stiffness parameter (α) 2) a decaying joint stiffness parameter (α) and 3) a linear relationship between joint stiffness (α) size of the reactivated joint.

The stages of the OU submissions against the GTO-CCS Challenge Problem #2 represented the benefit of the collaborative approach to the code comparison study, as the team re-evaluated their modeling approach with each GTO-CCS presentation, ultimately resulting in a mechanistic model. An unresolved aspect of the injection experiments conducted in September, 1974 in the GT-2 well, was the reason for the near 98% recovery of the water injected during the final injection, versus recoveries of less than 50% for the three previous injections. Brown et al. (2012) attributed this to the inclusion of a sand proppant in the final injection. The OU team opted to find an alternative explanation, given a recent evaluation during the GTO CCS that the volume of proppant-laden fluid was not sufficient of fill the well bore. In their first submission, the OU team was unable to match the final injection recovery without manually altering the residual aperture, for a fixed joint stiffness. In the second submission, the OU team noted good agreement with the experimentally observed fluid recoveries, when the joint stiffness was reduced with each injection. In the third submission, reported at the 50th U.S. Rock Mechanics / Geomechanics Symposium the team successfully demonstrated a new relationship between joint stiffness and the size of the reactivated joint that agreed with the Phase I Reservoir stimulation experiments. In terms of the objectives of the GTO-CCS, the outcomes from the OU team, offered numerical simulations that supported the theory that the fracture network comprised pre-existing natural factures that were initially sealed and no hydraulic fracturing occurred, but challenged the notion that sand proppant was solely responsible for the high fluid recovery noted in the final stimulation test.

3.4 Lawrence Berkeley National Laboratory

The team from Lawrence Berkeley National Laboratory (LBNL) had well established and internationally recognized capabilities for modeling coupled THM processes via their coupling of the TOUGH and FLAC^{3D} simulators (Rutqvist et at., 2002; Rutqvist, 2017), and chose to put those capabilities to bear against the reservoir creation and stimulation topical area of Challenge Problem #2, concerned with the Phase I Reservoir at Fenton Hill. This challenge problem addresses the series of experiments conducted during late September 1974 involving a suite of 5 reservoir stimulation injections of water into the open borehole section of well GT-2 between depths of 1981 to 2043 m (6498 to 6702 ft) , known as Zone 7. The LBNL team modeled this system as a well intersecting a finite thickness fracture element, tilted 70˚, within a finite volume computational domain. This modeling approach was adopted from a previous investigation of fault activation in shale (Rutqvist et al., 2015). Key elements of the approach were an exponential expression for fracture aperture versus effective normal stress, an anisotropic plasticity model allowing shear and tensile failure, strain-softening plasticity to represent sudden slip, and seismic moment and magnitudes from the Kanamori model (Izutani and Kanamori, 2001). Prior to modeling the series of injection experiments the LBNL team considered the potential for shear activation of a fracture oriented with a 70˚ tilt at the known depths for fracture intersections with well GT-2 within zone 7, with vertical stress of 53 MPa, minimum horizontal stress of 34 MPa, initial pore fluid pressure of 20 MPa, fracture cohesion of 1 MPa, and friction coefficient of 0.6. This analysis indicated shear slip of the fracture would occur at pore fluid pressures of 27.7 MPa, below the fracture normal stress of 36.2 MPa.

The LBNL modeling approach included the 2 km well length from the ground surface, specifying the experimental processes of injection, shut-in, and venting at the ground surface, as with the field experiment. All 5 injection stages were modeled via a single simulation execution, with the first short injection period being used, as with the approach of the OU team, to calibrate some fracture and well parameters, such as those used to describe the basic stress versus aperture function. Simulations were executed with both 5- and 60-min shut-in periods, and recovery rates were tracked during the shut-in and venting stages. Proppant and high-viscosity fluid effects were not considered in the simulations of the 5th injection period. Simulation results showed pressure fluctuations during the peak pressures due to rupture propagation with fracture shear dilation, and micro-seismic events were predicted with magnitudes between -2 and 0, due to slip on new fracture patches. A cumulative shear slip of roughly 5 cm was predicted and non-reversible permeability increases occurred with each injection period associated with shear slip, and reversible permeability increases occurred due to non-linear elastic response to pore fluid pressure fluctuations. The simulations showed good agreement with peak field pressure observations, but predicted lower flow recoveries. With respect to the objectives of the GTO-CCS, the LBNL team advanced their EGS modeling capabilities with the inclusion of algorithms for computing the effect on permeability of fracture opening by changes in effective normal stress and by shear dilation upon shear failure. Moreover, the team demonstrated the potential for progressive fracture aperture opening with each successive injection stage, due to shear dilation.

4. CONCLUSIONS

The pioneering work of the scientists and engineers on the Fenton Hill Hot Dry Rock (HDR) Project, from the early 1970s through the mid 1990s, remains relevant in our quest today to understand the creation and sustained thermal production of EGS reservoirs. Modern numerical simulators are analytical tools that provide us with capabilities for predicting both EGS reservoir creation and thermal performance, but more importantly insight into the fundamental hydrological, thermal, geomechanical, and geochemical processes within EGS reservoirs. The Fenton Hill Phase I and II reservoir experiments yielded an extensive amount of experimental data and observations, but also some lingering questions, as masterfully documented in Brown et al. (2012). Challenge Problems of the Geothermal Technologies Office Code Comparison Study (GTO-CCS) were specifically designed to investigate what new insights could be gained by recognized EGS modeling practitioners applying modern numerical simulators to selected questions concerning the creation, flow and transport behavior, and thermal recovery of two separate confined reservoirs at Fenton Hill. Each of the GTO-CCS Challenge Problems were based on one of the two Fenton Hill reservoirs, and were divided into three topical areas: 1) reservoir creation/stimulation, 2) reactive and passive transport, and 3) thermal recovery. For both reservoirs uncertainty remained about the structure of the stimulated volume and whether it comprises natural fractures, hydraulic fractures, or a combination of fracture types. In terms of reactive and passive transport and thermal recovery the debate over whether the reservoirs would expand, becoming more diffusive or collapse into a few high permeability channels remains open due to the limited lengths of the flow tests in both reservoirs at Fenton Hill.

Five teams submitted solutions against Challenge Problem #1, Fenton Hill Phase II Reservoir: 1) University of Nevada, Reno (UNR), 2) Pennsylvania State University (PSU), 3) Los Alamos National Laboratory (LANL), 4) McClure Geomechanics LLC (McCG), and 5) Stanford University (Stanford), with the McCG and Stanford teams combining on a single submission. The UNR team submitted against the hydrologic characteristics of the Fenton Hill Phase II reservoir, using new fracture and flow system modeling methodology and successfully demonstrated calibration against the experimental circulation flow tests was possible with a simple aperture fracture network model with just two parameters. The PSU team applied a new numerical simulator for modeling a randomly distributed fractured rock mass *via* an equivalent continuum approach to the question of the sustainability of the Fenton Hill Phase II Reservoir. The PSU team considered two reservoir concepts, one comprising a network of dense-short fractures and the other of sparse-long fractures – both honoring the microseismic data. These models predicted that >20MW$_{th}$ and >7MW$_{th}$ systems could be initially operated for the dense-short and sparse-long fracture networks, respectively These predictions are larger than the Fenton Hill HDR project simulation predictions of ~4 MW_{th} production over a 30-yr period, but the PSU simulations show significant thermal drawdown after ~2 years (50m case) and ~6 years (200m case), not sustained production for 30 years. The LANL team developed reduced-order model solutions to the questions of thermal performance and reservoir sustainability, based on higher order simulation of a conceptual model of the Fenton Hill Phase II reservoir. A principal objective of the LANL submission was to demonstrate the potential benefits of applying reduced-order models to EGS operations, compared with the more time consuming conventional numerical simulation approaches.

The combined McCG-Stanford team submitted solutions against questions associated with the creation/stimulation and thermal sustainability of the Fenton Hill Phase II reservoir. Their submissions challenged conventional theories concerning the nature of fractures in the reservoir, and proposed a mixed-mechanism conceptual model for describing the fracture network where fluid flow through the reservoir initiates where existing natural fractures intersect the well as the fluid pressure exceeds the fracture opening pressure, and then hydraulic fractures forming as splays or from the tips of the natural fractures, but terminating against natural fractures. The resulting network comprising natural fractures in their original orientation and a mesh of hydraulic fractures perpendicular to the minimum principal stress. This submission deviates from conventional theories about the nature fractures in EGS reservoirs, but supports the mixed-mechanism conceptual model through comparison of the simulation results against the experimental observations. Key elements in these comparisons were the orientation of the micro-seismic cloud, matching of the entire injection, shut-in, and flowback history with a single simulation assuming the lower stress gradient proposed by Brown in 1989, and the observation that injectivity below the threshold pressure did not increase significantly between injections.

The Fenton Hill Phase I reservoir was the basis for GTO-CCS Benchmark Problem #4, which only concerned the flow processes during circulation. Compared with the more idealized treatment in the benchmark stage, the challenge problem design was based on more comprehensive considerations of the field experiments and aimed to a better understanding multiple aspects of the field observations. For the GTO-CCS Problem #2 four teams submitted solutions all against questions concerned with creation/stimulation of the reservoir, specifically the series of five pressurization and venting experiments in Zone 7 of well GT-2 after stage 2 drilling of Fenton Hill Phase I, performed in September 1974: 1) McClure Geomechanics, LLC (McCG), 2) Lawrence Livermore National Laboratory (LLNL), 3) The University of Oklahoma (OU), and 4) Lawrence Berkeley National Laboratory (LBNL). All submissions were received after the problem refinements noted in Section 3.1.

The McCG team submitted a solution for all five experiments using a single simulation, and was able to reproduce the enhanced fluid recovery of the final experiment by accounting for fluid storage. The team additionally considered proppant effects within the fractured network and demonstrated much higher fluid recoveries during the final experiment with proppants entering the fracture network. However, McCG found that enhanced fluid recovery during the final experiment would have occurred even if proppant did not enter the formation. The McCG team concluded that fracture dilation by shearing only minimally contributed to the fracture permeability, and that there was not evidence for any other types of irreversible permeability enhancement.

The LLNL team approached the Fenton Hill Phase I reservoir problem with similar assumptions to those of the McCG team in terms of the conceptual model, based on an existing natural vertical fracture, but the foundational numerical methods of the computer codes used by these respective teams differed. Simulations showed significant water storage in the vertical fracture after each injection, shut-in, and venting cycle, due to collapsed apertures near the wellbore with reduced effective stresses during venting. Agreement with the experimentally observed recoveries during the 5th cycle were achieved via proppant inclusion and modeling the cross-linked gel as having ten times the viscosity of water. Of special note is the collaboration of the LLNL and McCG teams on a published manuscript that compares and contrasts the modeling approaches and outcomes for GTO-CCS Challenge Problem #2.

Submissions by the OU and LBNL team differed from those of the McCG and LLNL teams for the Fenton Hill Phase I reservoir creation/stimulation problem in that the OU and LBNL teams both observed irreversible changes to the fracture permeability with successive injection, shut-in, and venting cycles. An additional difference between the OU and LBNL teams and the McCG and LLNL teams was the assumption of a 70˚ tilt of the existing natural fracture in the geologic model (OU and LBNL teams), versus a vertical fracture (McCG and LLNL teams). Irreversible changes in the fracture characteristics with injection cycles were modeled in the OU simulation with a linear function between joint stiffness and the size of the reactivation joint, which increased with the injection cycle. In contrast the LBNL team realized irreversible changes in the fracture aperture through progressive shear slip and an associated fracture dilation.

The approach and principal objective of the Challenge Problem portion of the GTO Code Comparison Study was to apply established numerical simulators for EGS to the Fenton Hill reservoir problems, collaboratively discuss simulation results, and test new concepts to account for differences between the numerical results and experimental observations. Unresolved issues would then be used to establish research directions for GTO in the near future, particularly in the interim period between the conclusion of the study and the opening of the Frontier Observatory for Research in Geothermal Energy (FORGE) subsurface laboratory. In this respect the Challenge Problem portion of the GTO-CCS has largely succeeded, with each of the teams submitting solutions against the Fenton Hill Phase I and II reservoir questions, developing and adapting new modeling approaches in their numerical simulators, and challenging the accepted understanding of the mechanisms by which EGS reservoirs develop. A somewhat unexpected outcome of this study was that the highly collaborative nature of the discussions and partnering of teams yielded a diverse suite of modeling approaches, insights to the nature of the Fenton Hill reservoirs, and conclusions. But this diversity has been ideal for defining near-term experimental and numerical research objectives. Moreover, the collaborative nature of the study's approach induced participants to challenge themselves and established approaches, through a concentrated and open exchange of numerical simulation results against experimental observations.

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