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Simulating Hydraulic Fracture Stimulations at the EGS Collab: Model Validation from Experiments 1 and Design-Phase Simulation for Experiment 2

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ABSTRACT

The EGS Collab project focuses on intermediate scale (~10 - 20 m) EGS reservoir creation processes and related model validation at crystalline rock sites. It offers a great opportunity to validate computer simulations against extensive field observations that provide definitive characterization of the outcomes of hydraulic stimulations. In each of the two sets of Collab experiments, extensive modeling was performed to support experiment design. These modeling results constituted the basis for post-experiment validations. For Experiment 1, which focused on hydraulic fracturing, design-phase modeling successfully predicted the hydraulic fracture's strong tendency to propagate toward the drift. However, the role of rock fabric in determining fracture growth pattern was not realized until a significant discrepancy was observed in validation. The final enriched results matched well with experiment results. We also report simulation results to support Experiment 2 design, which will be validated after the experiments.

1. INTRODUCTION

The EGS (enhanced geothermal system) Collab project, sponsored by the United States Department of Energy (DOE), Geothermal Technologies Office (GTO), focuses on intermediate-scale (~10-20 m) EGS reservoir creation processes and related model validation at crystalline rock sites. The Experiment 1 and Experiment 2 testbeds are located near the 4850 ft and 4100 ft level drifts, respectively, at SURF (Sanford Underground Research Facility), formerly the Homestake Gold Mine, in South Dakota, USA. An important objective of the experiments is to validate computer codes that simulate and predict the hydraulic stimulations of fractures in EGS reservoirs. This is achieved by (1) extensive modeling and prediction of hydraulic stimulations in the design phase of the experiments, (2) thorough monitoring of the hydraulic stimulations to delineate hydraulic fracture propagation and natural fracture stimulations, and (3) using the observation data to validate and further improve numerical models.

For Experiment 1, stimulations were performed between May and December 2018, and flow tests were performed from early 2019 to early 2020. The testbed was dismantled in 2020. The simulations in the design phase and post-experiment model validations have been completed. The testbed for Experiment 2 is being constructed as this paper is written. Various fracturing simulations have been performed to support the testbed design and also to form the basis for post-experiment validation. This paper reports the simulation and validation results from Experiment 1, as well as the preliminary fracturing simulation results for Experiment 2.

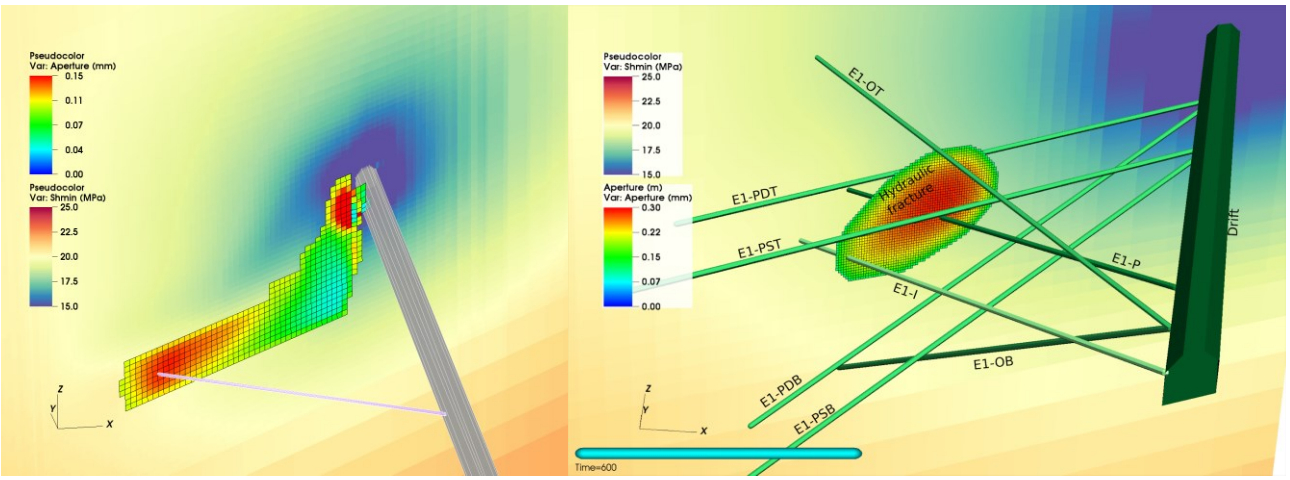
2. SIMULATION AND VALIDATION FOR EXPERIMENT 1

2.1 Fracturing Prediction in the Design Phase

Experiment 1 focuses on hydraulic fracturing, namely the creation a tensile-mode fracture from an injection well and the propagation of this fracture(s) to connect with a production well. As shown in Figure 1, both the injection well (named E1-I) and the production well (E1-P) were drilled along the estimated Shmin (minimum principal in situ stress) direction so that stimulated fracture(s) is largely perpendicular to the two wells. Six observation wells housing various sensors were drilled around the expected fracture location to provide adequate spatial coverage of the fracturing. Several ring-shaped notches were pre-cut in well E1-I. Stimulations were attempted through three of the notches at nominal depts of 128 ft, 142 ft, and 164 ft, respectively with varying results. Based on a comprehensive analysis of various observations, particularly microseismic locations (Schoenball et al., 2020), temperature anomalies along observation wells, and downhole camera footages in the production well, the stimulations from the 164 ft notch were determined to have created classic opening-mode hydraulic fractures (Fu et al., 2021). These simulations had conditions consistent with those for the design-phase modeling and simulation. The corresponding observations were used to validate and enrich the simulations. Injections from both the 128 ft and 142 ft notches were believed to have mainly resulted in the stimulation of various natural fractures in the testbed. No further characterization or flow testing was performed from these two intervals. The current section focuses on the stimulation from the 164 ft interval.

Multiple participating teams of the EGS Collab effort modeled the hydraulic fracturing process at Experiment 1 testbed in the design phase. The LLNL (Lawrence Livermore National Laboratory) modeling team, in collaboration with PNNL (Pacific Northwest National Laboratory), used STOMP to simulate the temperature field in the testbed and used GEOS to simulate the fracture process. The results were published in Fu et al. (2018) as shown in Figure 1(a). One of the most consequential findings from the design-phase simulation was the strong tendency of the fracture to propagate toward the drift. This tendency was caused by a large gradient of Shmin in a radial pattern around the drift, which was in turn induced by the cooling of the drift during the many decades of history of the gold mine and SURF. Note that the publication Fu et al. (2018) predated the stimulation activities of Experiment 1. The results as shown in Figure 1(a) suffers from a bias of the fracture trajectory from the underlying mesh structure.

Figure 1(b) shows further improved and refined simulation still before the commencement of stimulations in May 2018 but after the publication of Fu et al. (2018). The imprint of the underlying mesh structure in the fracture shape became inapparent. We also placed a “sink”, essentially a fluid pressure boundary condition at the cell where the fracture intersects the production well E1-P. Stimulation fluid can leak out of the fracture plane through E1-P, so this sink retards the further growth of the fracture. However, the “strength” of this sink depends on unmeasurable characteristics of the fracture-well intersection and can only be approximately treated in the model. Consequently, whether the sink can completely stop the fracture growth was unknown. Nevertheless, the prediction results showed that the fracture would intersect the production well, which achieves an important design goal of experiment.



(a) (b)

Figure 1: Simulation results of hydraulic fracturing at EGS Collab Experiment 1 in the design phase. (a) Results as published in Fu et al. (2018). The role of the production well was not represented in that version of the model. (b) Improved results after Fu et al. (2018) but still before the actual stimulation tests. The intersection with the production well E1-P was represented by a fluid “sink”. Numerical parameters were also tuned to minimize the effects of the underlying mesh structure on fracture shape.

2.2 Hits and Misses of the Design-Phase Predictions

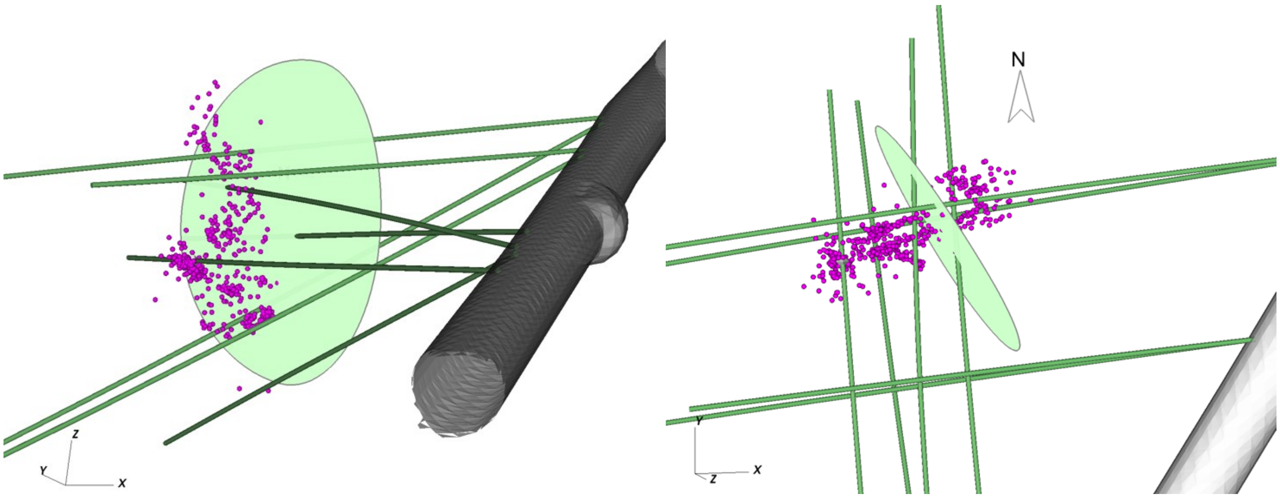
Detailed analysis of the outcomes of the stimulations from the 164 ft deep notch was performed and documented in Fu et al. (2021). It offered an opportunity to validate and further improve the simulation results. The microseismic results cleared validated the predicted strong tendency of the fracture to propagate toward the drift (eastward). There was no microseismic events to the west of the injection point except for events very close to the wellbore. The fracture also intersected the production well E1-P as predicted.

The main discrepancy between the simulation prediction and the actual fracturing observation was that the actual fracture spread much wider in the vertical direction than predicted. In other words, the actual fracture was “taller” than predicted. This assessment was further corroborated by the observation that the fracture intersected observation well E1-OT (OT = orthogonal, top). This discrepancy was the main target of improvement as described in Section 2.3.

The design-phase simulation could not predict the outcome that the stimulations resulted in two largely parallel, approximately 1.5 m apart, and slightly overlapping fractures. After extensive analysis in Fu et al. (2021), the relationship between these two fractures is still unclear. One possibility was that they both initiated from the injection interval; another possibility was that a fracture initiating from the pre-cut notch bifurcated during propagation. The sequence of microseismic events and the temperature anomalies in well E1-OT seemed to suggest the northern fracture, named fracture W-N in Fu et al. (2021), developed first while the southern one, named fracture W-S was stimulated in later stimulation episodes but gained dominance. As the distance between the two fractures is only a small fraction of the sizes of the fractures and they only slightly overlapped, in validation simulations we still only simulated one fractures and tried to match the combined spatial extents of the two fractures.

The design-phase simulation also did not capture the role of a major natural fracture, named “OT-P Connector” and visualized as the green plane in Figure 3. According to the analysis in Fu et al. (2021), the hydraulic fracture(s) initiated from well E1-1 and propagated towards OT-P Connector. Upon intersection, the hydraulic fracture(s) was partially “arrested” by the natural fracture due to the latter’s high conductivity. Prolonged injection in at least two stimulation episodes did enable the fracture(s) to continue to propagate to the east of OT-P Connector, although the fractures on the east side apparently deviated from the original fracture trajectories in the west side. The prominent presence and remarkable role of OT-P Connector were obvious in hindsight: It was visible with variable but generally large apertures in cores from five wells. Unfortunately, it was not known to the fracturing modelers in the design phase. The so-called

"Common-DFN" model, a collection of cataloged natural fractures as well as basic interpretations of their relationships, was only released to the EGS Collab project team in December 2018. In the post-testing modeling effort, we focused on the fracture propagation prior to the intersection with OT-P Connector. Post-intersection behavior was dominated by circumstantial factors that are not measurable.



(a) (b)

Figure 3: The propagation of hydraulic fractures from E1-I's 164 ft deep notch as inferred from microseismic data. Microseismic events are shown as magenta dots. The OT-P Connector is shown as a green plane. The combined extents of the two closely spaced parallel fractures to the west of OT-P Connector are visible in (a). The lateral offset (in the north-south direction) between the two fractures is visible in (b)

2.3 Realizing the Role of Rock Fabric in Fracture Propagation

"Fabric" refers to the inherent structure of rock, particularly the layered structure in sedimentary rocks. Earlier works (e.g., Fisher & Warpinski, 2012) analogized horizontally layered sedimentary rocks to composite materials to explain why hydraulic fractures tend to grow horizontally more than vertically (i.e. across layers). Fu et al. (2019), a recent paper by LLNL's GEOS team discovered the "roughness" of in situ stress, namely the variation of in situ stress across rock layers, can result in an effective anisotropy in rock toughness. This is essentially an additional mechanism to make it harder for a hydraulic fracture to propagate across rock layers than to extend in other directions. The role of rock fabric in affecting hydraulic fracture shapes was commonly recognized in the context of fracturing in sedimentary rocks, where the layered structure is ubiquitous. As the bedding planes of shale plays, the main source rock exploited in unconventional oil and gas production, are usually horizontal, this effect usually manifests into hindered vertical growth of fractures and more horizontal growth.

The rock that constitutes EGS Collab Experiment 1 testbed, mainly phyllite, is a metamorphic rock. The Collab modeling team did not connect the aforementioned concept to the testbed in the design phase. In light of the observation that the observed hydraulic fractures spread much wider in the vertical direction than previous predicted based on a smooth rock assumption, we started to suspect that it was caused by the rock's fabric. Reconciling various aspects of evidence, we realized that fabric analogous to those in sedimentary rocks actually exists in the testbed. We found that there exists a pervasive set of natural fractures that either reflects or was rooted in this rock's fabric. As shown in Figure 4, most of the natural fractures and foliation planes as logged in the eight wellbores are largely vertical and strike northwest-southeast. On average these fractures strike N140°E. On average, the hydraulic fractures on the west of OT-P Connector strike N75°E, and dip 80°C. Therefore, the hydraulic fractures cut the fracture/foliation planes at a 65° angle. When the fractures grow eastwards, they have to penetrate across parallel fracture/foliation planes in the rock, consuming more energy than growing in the vertical direction in the same plane. This propagation mode is analogous to a vertical hydraulic fracture in a shale play grows upwards.

Such speculated rock fabric is corroborated by sonic logs collected from two wells, well E1-P from the Collab Experiment 1 testbed and well k003 from the kISMET project (Oldenburg et al., 2016) which was very close to the Collab testbed. Well E1-P penetrates the fracture/foliation planes at 40°. The significant variation of P-velocity in short wavelengths along E1-P likely reflects the significant variation of rock properties across fracture-foliation planes. Well k003 is largely parallel to the fracture/foliations planes. Therefore, the P-velocity profile is much smoother along this well.

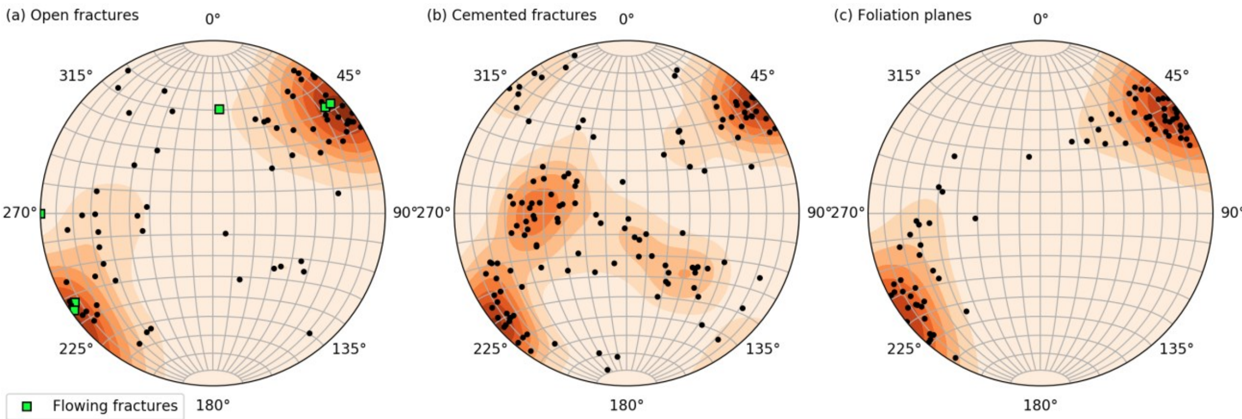


Figure 4 Lower hemisphere pole plots, including density contours of the orientations of fractures and foliation planes logged in the eight wells. In (a), the five "flowing fractures" are denoted by green squares. The natural fracture catalog is included in the Supporting Information.

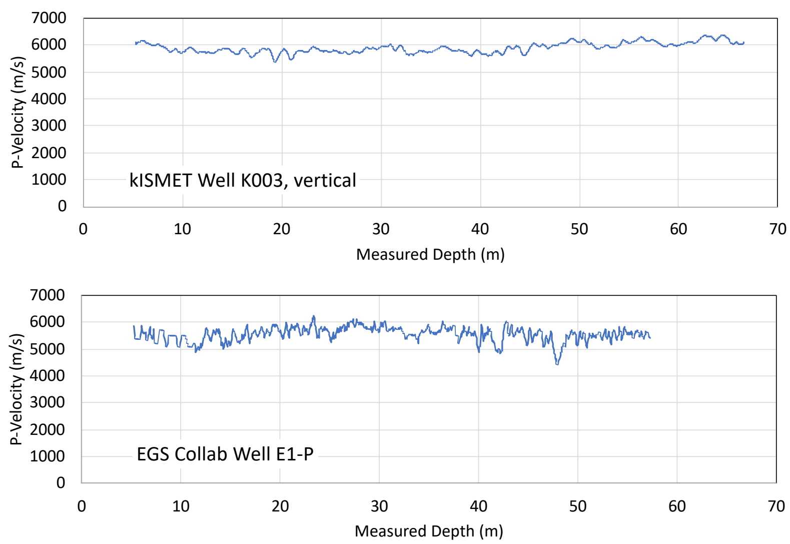


Figure 5 Rock wave velocity profile along two wells as measured using sonic logs. kISMET Well K003 was a vertical well near the Collab Experiment 1 test bed. Because the pervasive natural fractures and foliation planes are largely vertical, K003 should be roughly parallel to these planes. E1-P penetrates across the fracture/foliation planes, resulting in variations of P-velocity in short wave lengths.

2.4 Modeling the Role of Rock Fabric in Fracture Propagation

To test the hypothesis that the rock fabric in the testbed, in the form of vertical fracture/foliation planes striking northwest-southeast, had caused the wide spread of hydraulic fracture in the vertical direction, we further enhanced our design-phase fracturing model as follows. We assumed the spatial variation of Shmin due to cooling from the drift still dictates the overall Shmin gradient in the testbed. We superposed a random perturbation to the Shmin to represent the effects of rock fabric. The perturbation is an auto-correlated random field generated following the procedure as described in Guo et al. (2016). The correlation length in the horizontal direction, or the direction between the injection well and the drift, is assumed to be 1.2 m. The correlation length in the vertical direction is assumed to be 4.0 m. The standard deviation of Shmin in the perturbation field is 0.5 MPa. The short correlation length in the horizontal direction reflects the variation of rock properties/states among layers divided by fractures and foliation planes.

Updated simulation results are shown in Figure 6. Due to the stochastic nature of the applied stress perturbation, we generated multiple realizations but only show results from one realization in Figure 6. Although the fracture shape does not exactly cover all the microseismic events, it does capture the height growth of the fracture reasonably well, to some extent validating the hypothesis regarding the role of rock fabric in fracture shape development.

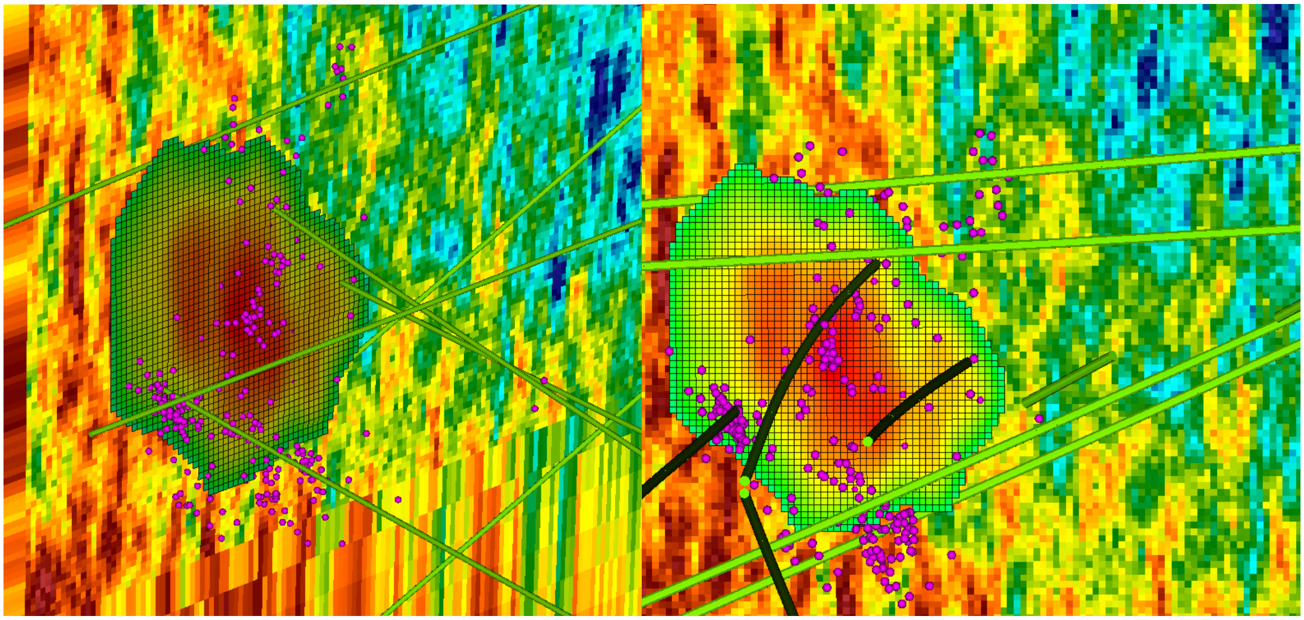


Figure 6 Simulation results after incorporating an auto-correlated perturbation to the Shmin field. The two figures are snapshots taken from two different angles.

3. DESIGN-PHASE FRACTURING SIMULATIONS FOR EXPERIMENT 1

3.1 Simulation Rationale

EGS Collab Experiment 2 focuses on hydraulic shearing of natural fractures as a mechanism to enhance naturally fractured rock formation's permeability. Experiment 2 testbed is being constructed at the 4100 ft level (nominal depth of 4100 ft) of SURF. Fracturing simulations have been performed by the LLNL team to support the design and planning for Experiment 2. This section briefly summaries these simulations.

Although the main research target of Experiment 2 is hydraulic shearing, we chose not to perform any hydraulic shearing simulation. This is because the outcome of hydraulic shearing highly depends on in situ characteristics of natural fractures such as the strength of cementation and natural permeability. Both characteristics are known to be highly variable even along the same fracture and cannot be reliably measured. The uncertainties in the simulation parameters are apparently greater than the value of hydraulic shearing simulations in the design phase. We only performed fracturing simulations that rely on parameters that can be reasonably constrained based on field measurements and general knowledge in rock mechanics. These simulation results should have direct impacts on experiment design decisions and stimulation data interpretation.

3.2 Simulating Hydraulic Fracture Trajectory

Hydraulic fracturing could occur at Experiment 2 under at least two circumstances: First, if the breakdown pressure for natural fracture is high and certain natural or drilling-induced defects along the injection well exist, an opening-mode hydraulic fracture could initiate and propagate. Second, if hydro-shearing proves ineffective in enhancing rock permeability of the testbed, the Collab team might deliberately stimulate hydraulic fractures to continue the experiment.

The testbed design team are concerned with at least two aspects of the outcomes of hydraulic fracturing:

1. To avoid fracture intersecting the drift, and
2. To maximize the likelihood of the fracture intersecting production wells.

Based on learnings from Experiment 1, we appreciate the significant effects of in situ stress gradient and rock fabric. Rock near the testbed has many natural fractures but none of the fracture sets seems to dominate the rock fabric. The Experiment 2 testbed is expected to have a radial temperature gradient around the drift due to cooling similar to that at the Experiment 1 testbed. Experiment 2 had the advantage of having drilled a vertical test well TV4100 from the drift to make important measurements, such as temperature gradient and in situ stress. Two interpretations of Shmin along TV4100 are shown in Figure 7. The black circles show an interpretation (Interpretation A) assuming a linear vertical gradient of Shmin in the unperturbed rock (before mining activities) and superposing calculated thermal stress based on temperature logs. The red circles show an Shmin profile (Interpretation B) fitted to 10 mini-frac tests along the well. The results show that Shmin in a rhyolite layer below the drift is significantly lower than Shmin in the amphibolite layer. The vertical gradient of Shmin near the amphibolite-rhyolite interface is reversed, meaning locally Shmin decreases as depth increases.

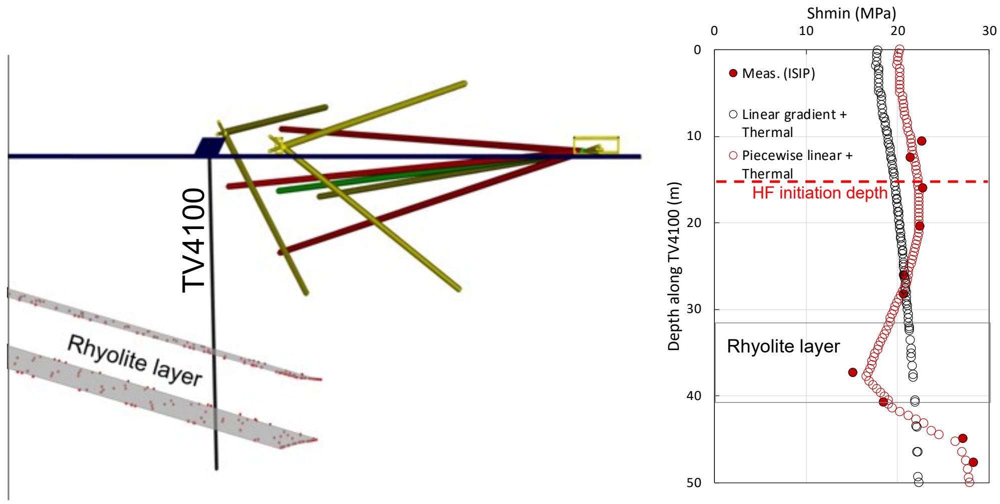
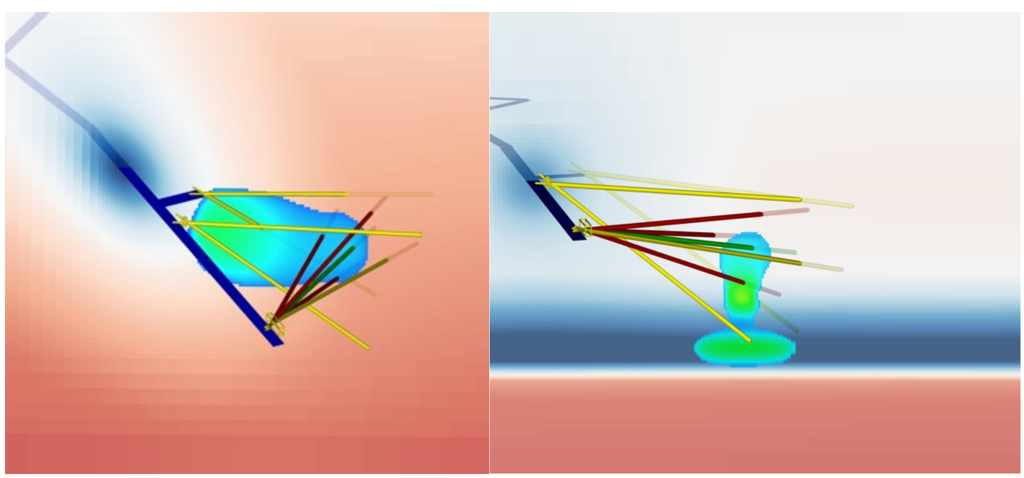


Figure 7 Layout of Experiment 2 testbed (left) and interpreted Shmin distributions along well TV4100. A rhyolite layer that seems to cause a stress anomaly is shown.

Fracturing simulation results based on these two interpretation results are shown in Figure 7. Under Interpreation A, The fracture would have a strong tendency to propagate toward the drift. The height (vertical extent) of the fracture is moderate but we anticipate, based on learnings from Experiment 1, that the actual height would depend on rock's fabric, which is poorly understood at this moment. Under Interpretation B, which is a more reliable interpretation, the fracture would first grow downwards toward the rhyolite and then propagate within the rhyolite. In both scenarios, the fracture would intersect at least one production well.

Note that although the propagation of hydro-shearing zones is likely to follow stress gradient direction (i.e. towards lower stress) as well, the sensitivty of its propagation to stress gradient is much less than the propagation of hydraulic fracturing. How the zone of hydraulic shearing is going to propagate during stimulation cannot be predicted in the design phase.



(a) Based on stress interpretation A. (b) Based on stress interpretation B

Figure 8 Simulation results after hydraulic fracture propagation in Experiment 2. Fracture shape, aperture distribution, and intersection with production/observation wells are shown. (a) is based on stress interpretation A assuming radial thermal stress superposed onto a linear stress gradient; (b) is based on stress measurements in well TV4100.

4. CONCLUSIONS

In this paper, we provided an overview of fracture stimulation simulations performed by the EGS Collab LLNL team in collaboration with other Collab teams for the two sets of experiments in the EGS Collab project. With the completion of Experiment 1, we finished the prediction-experiment-validation-enhancement cycle. The design-phase simulation successfully predicted the fracture's strong tendency to propagate toward the drift. However, the predicted fracture did not spread wide enough in the vertical direction compared with field observations. Additional knowledge about the testbed gained during Experiment 1 alluded to the role of rock fabric. After incorporating a heterogeneous perturbation to in situ stress consistent with the rock fabric pattern, the modeled fracture shape became similar to the shape observed in the field. This effort not only "validated" GEOS's ability to model and predict hydraulic fractures. More importantly, it also revealed the previously unappreciated role of non-sedimentary rock's fabric in determining the shape of hydraulic fractures. This revelation could have important implications for hydraulic fracturing in the context of EGS.

We also presented recent modeling results serving the design of EGS Collab Experiment 2. The results again emphasized the importance of quantifying in situ stress gradient in predicting fracture propagation pattern. As Experiment 2 testbed is still under construction, the validation of these results will be reported after the experiment.

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