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Feasibility Evaluation of Potential Stimulation Methods for Collab Experiment 3

Recommendation Report

Earl Mattson, Douglas Blankenship, Henry (Bud) Johnston, Luke Frash, Joe Morris, Timothy Kneafsey, Jennifer Miskimins, and the Collab Team

December, 2017

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Idaho National Laboratory
Idaho Falls, Idaho 83415

http://www.inl.gov

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SUMMARY

In support of the Collab Project Milestone 1.4, INL is to submit a recommendation report describing feasible methods to investigate during Experiment 3 to DOE. This report fulfils this FY18Q1 SMART milestone.

Twenty one potential methods were consideration for testing as part of Collab Experiment 3. The potential methods have been categorized as; Fracture Initiation, Stimulation Fluids, Stimulation Methods and Flow Control. The categories have been further divided into three general groups (e.g. high, medium, low) based on applicability to the scale of measurement at Collab (~10 meter) and it's applicably to FORGE. The highest relevant methods (not necessary in order) are: 1) fracture initiation within the borehole, 2) use of slickwater fracturing fluids, 3) use of viscous fracturing fluids, 4) simultaneous stimulation of multiple wells, 5) use of energetic fluids to initiate larger fractures or connect a borehole to existing fractures, 6) injection of diverters to control short circuits and working fluid loss, 7) testing of borehole isolation techniques to control water flow pathways in the reservoir, and 8) use of multiple injection and production wells to characterize a fracture.

Fractures created in Experiments 1 and 2 offer the opportunity to test engineering solutions to issues encountered in the stimulation process or during the fracture flow testing. An advantage of using these sites is that there would be a wealth of baseline characterization data for the site, and the borehole monitoring system and experimental infrastructure is already established and could possibly be reused.

This suggested potential method list should be considered preliminary due to the timing of this report and the status of Collab Experiments 1 and 2 as well as the need for preliminary modeling to assess each of the proposed methods effectiveness.

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Direct questions to Dr. Earl Mattson at the Idaho National Laboratory.

Earl.Mattson@inl.gov

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ACRONYMS

DEM	Discrete Element Method
DOE	Department of Energy
EGS	Enhanced Geothermal Systems
FLAs	Fluid Loss Additives
FORGE	Frontier Observatory for Research in Geothermal Energy
GTO	Geothermal Technology Office
kISMIT	permeability (k) and Induced Seismicity Management for Energy Technologies
O&G	Oil and Gas
R&D	Research and Development
SubTER	Subsurface Technology and Engineering Research, Development, and Demonstration
SURF	Sanford Underground Research Facility
THMC	Thermal-Hydrological-Mechanical-Chemical

Feasibility Evaluation of Potential Stimulation Methods for Collab Experiment 3

1. Introduction

To facilitate the success of FORGE, the DOE GTO has initiated a new research effort, the EGS Collab project, which will utilize readily accessible underground facilities that can refine our understanding of rock mass response to stimulation and provide a test bed at intermediate (on the order of 10 m) scales for the validation of thermal-hydrological-mechanical-chemical (THMC) modeling approaches as well as novel monitoring tools.

EGS Experiments 1 and 2 will create testbeds where we will perform and characterize a number of intensely monitored stimulations. Detailed measurements of permeability enhancement and characteristics of the stimulated rock will provide insights into the nature of stimulation (e.g., hydraulic fracturing, hydroshearing, mixed-mode fracturing, thermal fracturing) in crystalline rock under reservoir-like stress conditions and generate high-quality, high-resolution, diverse data sets for model validation. In addition, these tests will facilitate evaluation of monitoring techniques under controlled conditions to allow selection of technologies appropriate for deeper full-scale EGS sites. EGS Experiments 1 and 2 will be performed under different stress/fracture conditions, and will evaluate different stimulation processes: Experiment 1 will focus on hydrofracturing, while Experiment 2 will concentrate on hydroshearing of an existing fracture. Having multiple tests conducted under different conditions is important because it provides appropriate data for model comparison and leads to a better understanding of different stimulation mechanisms and their efficacy in creating reservoir permeability.

EGS Experiment 3 will begin in year 3 (i.e. 2019) and will investigate alternate stimulation and operation methods to improve heat extraction in an EGS reservoir. We envision this task as conducting new experiments in the testbeds prepared for EGS Experiments 1 and 2, improving on stimulations previously performed, and performing new stimulations with alternate methods (different fluid properties, different pressure applications, use of proppants, or other high-risk high-reward methods that can be evaluated in a scaled environment).

2. Anticipated Issues to Development of an EGS

Creating an efficient heat extraction system in the subsurface is a difficult task. For engineering purposes, fractures are often modelled as simple 2D systems with simple geometries. In reality, hydraulic fractures exhibit complex geometries controlled by rock structure and strength, regional and local stress fields, existing discontinuities such as fractures and faults, as well as engineering parameters such as pumping rates, injected fluids and well construction (Figure 1).

The two technical parameters with the highest economic uncertainty and risk for EGS are flow rate per production well and thermal drawdown rate. These two parameters basically define the thermal energy that can be extracted from the subsurface. In engineering terms, this requires creating a fracture system that: 1) has high permeability, 2) where each fracture has a 'uniform' flow pathway, 3) has a large surface area that contacts hot rock, and 4) can maintain these attributes for a long period of time. Appendices 1and 2 list current EGS projects. Appendix 3 list new GTO funded R&D projects.

Figure 1. Idealized KGD geometry of a 2D fracture (from Gidley et.al. 19889) and a mine back view of a hydraulic fracture highlighted with green proppants (from R. Jeffery, CSIRO)

2.1 Fracture Permeability

Well productivity remains the greatest technological challenge for the commercialization of EGS (DOE, 2008). Commercialization production rates in this case has been defined somewhere in the range of 50 to 100 kg/s (Ziagos et.al. 2013). The MIT report reported this value as 85 kg/s. Of the EGS projects to date, Soultz (France) has had a maximum well productivity of about 25 kg/s.

In contrast, vast increases in well injectivity have been attributed to thermal contraction in many cases. Injection rates into low permeable reservoirs at Raft River and the Geysers have been successful after a long term injection of cold water.

2.2 Short-Circuits

The longest period of continuous performance of an EGS system was at Rosemanowes. Fluids were circulated at Rosemanowes for three years, during which production temperatures fell from 80 to 55°C, (DOE, 2008) and suggest a short circuit developed. In another field study, Hawkins et al. (2017) concluded that a narrow channel between the injection and the production wells dominated the flux of injected water at the Altona field site in New York. Fluid flow channel will reduce the thermal lifetime of reservoirs and will be exhibited by lower temperatures at the production well. Little study has examined engineering solutions to control fast flow pathways in EGS systems while creating a uniform heat extraction system.

2.3 Surface Area/Volume

Commercial EGS will require a reservoir volume on the order of a cubic kilometer of fractured rock to sustain heat extraction. EGS projects such as Soultz have achieved such goals via hydraulically connecting wells to the natural fractured system in a fairly well confined system. However, test conducted at other EGS projects such as Rosemanowes have illustrated that due to the high injection and extraction well pressures, continue reservoir growth can be an issue.

2.4 Sustainability

A management goal of an EGS is to maintain the thermal energy output for long periods of time. Therefore it will be necessary to optimize the extraction of heat, maintain the flow rate, prevent fluid loss during circulation, and minimize other parasitic power losses (DOE, 2008). Introducing new fluids into the subsurface that are out of chemical/thermal equilibrium can create long term consequences of EGS performance. There is little practical operational experience in optimizing an EGS subsurface reservoir.

2.5 Minimize Working Fluid Loss

One often overlooked EGS parameter is maintaining the mass balance of the injected and produced fluid. Loss of injected fluid to the formation will result in excess makeup water. The MIT report assumed an EGS system would loses up to 2% of total injectate during reservoir operation. Field tests have reported much higher fluid losses, (e.g. Rowemanowes->70%, Hijiori- >70%, Fjallbacka - ~50%, Ogachi 70-90%), suggesting that fluid losses can be a major issue in effectively operating an EGS site. Petroleum created fractures often use fluid loss additives (FLAs) to control fluid loss during the creation of a fracture. FLAs products can range from chemical additives that form a filter cake along the fracture wall impeding fracturing fluid loss to the formation. For higher permeable formations including those with natural fractures particulate matter (e.g. silica flour/fine sand) is added to physically block large pores and allow a filter cake to form. The use and injected concentrations of particulate FLAs to control fluid loss is mainly based on field evidence and available materials (Smith and Montgomery, 2015). These petroleum fluid loss control methods may not be applicable to EGS sites.

3. SURF EGS Experiments

Although the experimental location for Experiment 3 has not been determined, it is likely that some of the experiments to be conducted for Collab Experiment 3 will take advantage of the infrastructure used at Experiments 1 and 2. Tests could be conducted within the fracture systems created in these two tests or adjacent to the previous sites. Data collected from Experiment 3 can be compared to the previous experimental results or used independently.

The Sanford Underground Research Facility (SURF) in South Dakota is the host of the EGS Collab project experimental site. SURF is located in the former Homestake gold mine in Lead, South Dakota, and is operated by the South Dakota Science and Technology Authority. It is the host to a number of world-class physics experiments related to neutrinos and dark matter, as well as to geoscience research projects (Heise, 2015).

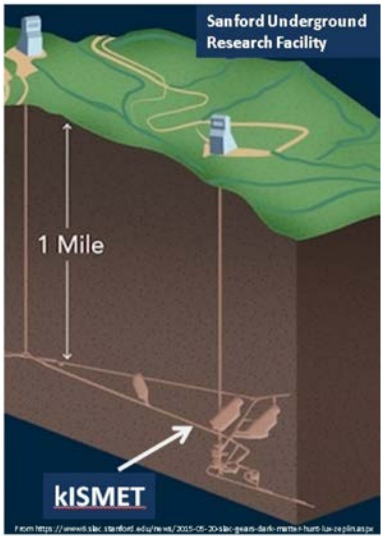
A general geotechnical review of the rock properties and state of stress for the SURF facilities can be found in a report written by Peter Vigilante (2016). For a specific site in the Homestake mine, one would have to perform hydrofracture experiments to establish the stress values and orientation due the high variability of the stress measurements measured in the Homestake mine.

Three potential sites are discussed in the following sections.

3.1 kISMIT

In support of the DOE SubTER Crosscut initiative, a team comprising national laboratory and university researchers has established the kISMET (permeability (k) and Induced Seismicity Management for Energy Technologies) field test facility (Figure 2) at the 4850 level of the Homestake mine (Oldenburg et.al., 2017) and provides some of the most relevant stress measurements for Collab project Experiment 1. The project objectives were to conduct modeling and field experiments to measure stress orientations and magnitude, conduct hydrofracturing in crystalline rock to enhance permeability, evaluate different monitoring techniques, and monitor associated induced seismicity.

Five near vertical wells were drilled and eleven stimulation tests were conducted beneath the floor for the 4850 level.



Test	Depth		Measured Depth		Cycle 1 Breakdown Pressure, P_b
	m	feet	m	feet	MPa
Stimulation, Test 11	1519	4982	40.23	132	22.9
Test10	1532	5027	53.95	177	30.4
Test7	1540	5052	61.57	202	29.5
Test9	1546	5072	67.67	222	23.6
Test8	1548	5079	69.80	229	24.6
Test5	1552	5091	73.46	241	29.5
Test4	1558	5112	79.86	262	26.3
Test3	1563	5129	85.04	279	27.6
Test6	1568	5143	89.31	293	26.9
Test1	1573	5162	95.10	312	*32.7*
Test2	1576	5169	97.23	319	*33.7*

Figure 2 Location of the kISMIT site and table of breakdown pressures measured (Oldenburg et al., 2016).

The largest kISMET stimulation involved a net of 28.1 liters (Oldenburg et al., 2016, page 90) and might be expected to have a radial extent of 6 to 11.4 m for the toughness-dominated solution. Unfortunately, there was no independent verification of the dimensions of the induced fractures from the kISMET experiment (Oldenburg et al., 2016). Since the hydraulic fractures did not intersect other wells, not flow tests were conducted in these fractures. The fractures were used to estimate the formation permeability through a slug test analysis (see section 4.1.6).

3.2 Collab Experiment 1

Based on coordination between the Experiment 1 characterization, design, stimulation, and flow test task groups and the characterization, modeling, experiment design, and monitoring working groups, a preliminary borehole configuration for the first experiment was developed (Figure 3). This design is based on having near-horizontal stimulation and production boreholes with a slight down dip that are oriented perpendicular to the orientation of the expected hydrofractures, and that are spaced 10 meters apart. A suite of monitoring boreholes is planned to allow for sensors to be located near the location of the anticipated fracture plane, facilitating monitoring of fracture propagation and fluid flow within the fracture system.

All of the boreholes are expected to be entirely within the Poorman Formation, a metasedimentary rock consisting of sericite-carbonate-quartz phyllite (the dominant rock type), biotite-quartz-carbonate phyllite, and graphitic quartz-sericite phyllite (Caddey et al., 1991). Carbonate minerals are calcite, dolomite, and ankerite. The rock is highly deformed and has veins/blebs of carbonate, quartz, and pyrrhotite, with minor pyrite. Other mineral phases (in addition to those listed above) include graphite and chlorite.

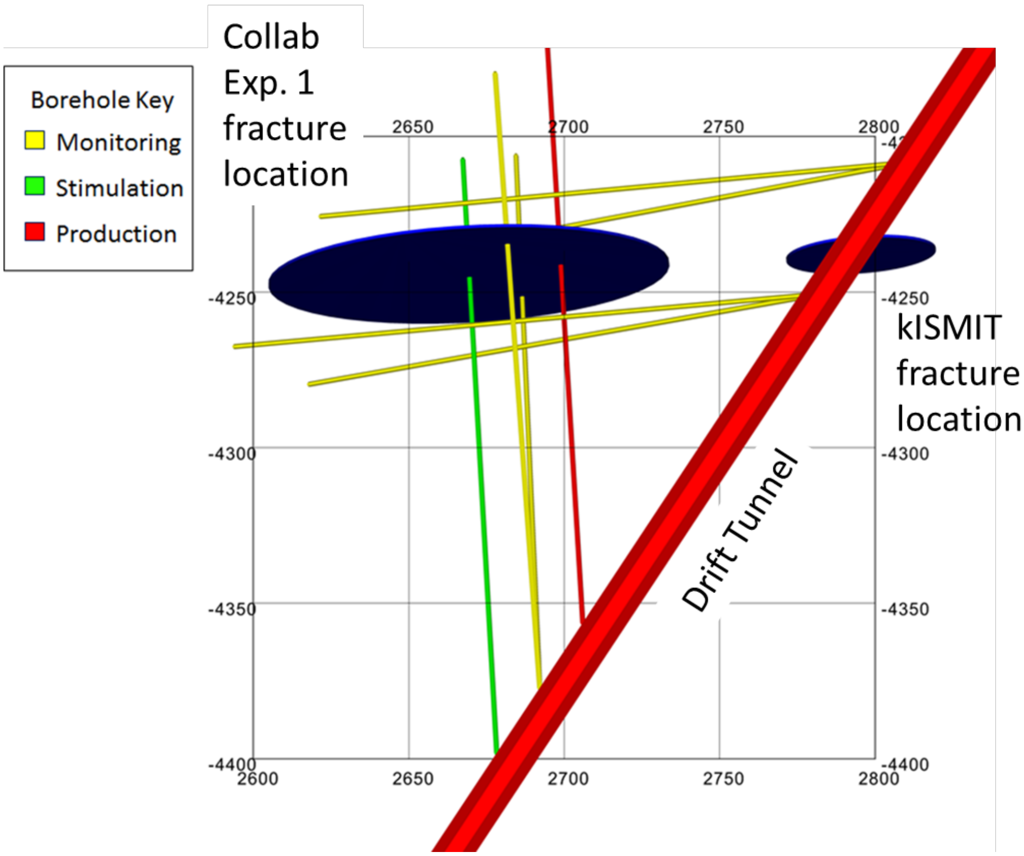


Figure 3. Plan view of the proposed EGS-Collab Experiment 1 layout. Experiment 1 stimulation represented by the larger of the two black disks and the previous kISMET stimulation indicated by the smaller disk.

The Experiment 1 plan is to injection rate of 0.1 L/s for 10 mins of injection (60 L total). A preliminary toughness-dominated solution predicts a radius of 15.5 m and aperture of 118 microns. It should be noted that this prediction does not include leakoff.

Experiment 1 is currently on-going and stimulation and flow testing will begin in 2018. Currently, all the wells have been drilled. The injection well has been notched in five locations.

3.3 Collab Experiment 2

Experiment 2 will actively seek a test bed where a contrasting set of conditions is encountered, e.g., natural fractures are present and the stress conditions are suitable for an investigation of hydroshearing and mixed mechanism stimulation concepts for permeability enhancement. Essential elements for the hydroshearing/mixed mechanism stimulation experiment site include the presence of a network of optimally oriented, critically stressed natural fractures that have sufficient roughness and permeability for an injected fluid to induce permanent slip and dilatation. This test location will initially be sought at SURF, however other locations may be evaluated and ultimately selected.

4. Collab Experiment 3 Potential Methods

The primary remaining technical challenges for EGS relate to how best to fracture deep rock to create sufficient connectivity within injection wells and production wells in such a way as to generate adequate power without cooling the reservoir and reducing its lifetime and increasing the time for investment cost recovery (Stephens and Jiusto, 2009). Unlike the improvements that drilling technology has seen in the last few decades, fracturing technology still uses for the most part technologies that were developed in the 1950s and 1960s (Smith and Montgomery, 2015).

The objective of Experiment 3 is to evaluate potential stimulation processes as to their ability to increase fracture conductivity and uniformity in crystalline rock, evaluate fracture sustainability under EGS conditions, and predict these improvements via numerical models and validate these model results through field tests to be carried out in years two and three. To achieve this objective, numerous discussions were held within the Collab team where a list of potential fracturing methods and fluid circulation techniques was developed. Table 2 lists potential methods that could be examined in Collab Experiment 3. The table is organized in four categories; Fracture Initiation, Stimulation Fluids, Stimulation Methods and Flow Control.

The four categories were further segmented into 3 group; High, Medium and Low Relevance. These groups are color coded: Green, Blue, and Yellow respectively (see Table 1). Potential methods that seemed most appropriate for testing for Collab Experiment 3 were grouped using the following criteria:

- Ability to implement at Collab
- Ability to examine result for improvement over other techniques
- Relevance and scalability to FORGE/EGS
- Degree of technical readiness level

It should be noted that the ranking of these groups will likely changes as we obtain fracturing and flow results from Collab Experiments 1 and 2. For instance, preliminary observations from Collab Experiment 1 suggest a number of anomalies from our initial geologic conceptual model of the Experiment 1 test site. For example:

- there exists a temperature gradient within the test site due to cooling of the west drift,
- core logging of the boreholes in Experiment 1 reviled that there is more quartz heterogeneity in this location than initially thought,
- drilling also suggested a permeable flow pathway exists between some of the boreholes.

We can expect to see even more anomalies during Experiment 2.

Table 1. Reviewed methodology summary table for Experiment 3.Methodology rating; Green-high relevance, Blue-relevant, Yellow-low relevance.

Method	Benefits	Drawbacks	Collab – Applicability	FORGE – Applicability
Fracture Initiation				
Fracture seeding - Notching, perfing	- Initiation of fracture within a borehole		- Notch appears promising for research - Perforation via shape charges is possible	- Perf guns are an existing FE technology
Short interval flexible packer	- Engineering technology to initiate a fracture		- May not be critical	High temperature effects
Fracturing at the toe	Could fracture as drilling	Would need further engineering development	- Similar to short packer	
Thermal stress alteration fracture	- Secondary recovery of thermal heat		- Hard to develop significant thermal stress at Collab	- Not likely to be used at FORGE
Stimulation Fluids				
Viscous Fluid Gel Hydrofracture	- Existing FE technology - Encourages tensile fracture - Good direction control	- Reduced shear fracture likelihood - Complex fluids - Hard to clean fracture		Probable fluid choice for FORGE
Water/Slickwater Hydrofracture	- Existing FE technology - Encourages shear	- Difficult direction control - Can encourage shear - Fluid reactive with minerals	- Being evaluated in Experiment 1	Probable fluid choice for FORGE
Acid Injection or Fracturing	- Existing FE technology - Maybe effective for carbonaceous rocks and calcite infilled fractures	- Use of hazardous chemicals - Borehole stability issues	- Desert peak examples	- Not likely to be used at FORGE
Non-water CO2 (other gases) Fracturing	- Lesser chemical scaling potential	- Likely complex or tight fracture network after closure- Confined working space safety concerns		- Not likely to be used at FORGE
PNNL swelling fluids				- Not likely to be used at FORGE

Method	Benefits	Drawbacks	Collab – Applicability	FORGE – Applicability
Stimulation Method				
Simultaneous multiple well fracturing	- Modeling suggests that fractures would join due to stress shadow	- Fractures would have to be close enough to be influence by stress shadow	- May be hard to develop stress shadows at Collab - Concern at fracturing near drift	- Schultz has attempted with reported success
Energetic Fracturing	- Existing FE technology - Increased near-well fracturing	- Borehole stability issues - Safety and handling issues - Near well damage zone	- Scalability to field?	
Oscillatory/Pulse Fracturing	- May improve fracture permeability - May extended fracture network - May improve flow distribution	- Less developed technology - Seismicity dependent on magnitude of over pressured	- Could be implemented but would be hard to validate effects	
Mechanical Impulse Fracturing	- Improved fracture permeability - Controllable high pressure - Different fracture geometry	- New technology - Increased seismicity potential - Not well developed		- Not likely to be used at FORGE
Thermal Fracturing	- Likely to occur in EGS anyways - Can extend fracture network - Can dilate fractures	- Requires large temperature gradient - Not well understood - Reversible? - Difficult to control temperature	- Cannot get sufficient delta T for thermal fracturing at Collab	May occur to some extent at FORGE
Long Term Injection	- Encourages shear/thermal effects - May occur during flow testing	- Time consuming - High induced seismicity potential seen in FE	- Not applicable at Collab	- Likely to occur in EGS to some extent
Electro-fracturing	- Different fracture geometry	- Alters rock mineral structure		- Not likely to be used at FORGE

Method	Benefits	Drawbacks	Collab – Applicability	FORGE – Applicability
Flow Control				
Borehole zonal isolation and flow control	- Engineering development of borehole flow control between fractures - Passive and active systems exist in FE	- Current devices are generally < 5½” diameter - High EGS temperature could be a potential issue - Cost could be a factor at EGS	- Collab can simulate zonal control using standard packer, tubing and pump control to assess impact and validate models	- There are existing downhole flow control devices in the FE market
Injection of proppants	- Can be optimized for geophysics - Permeability at low net pressure	- More complex machinery - Difficult proppant selection - - Not a feature of some models	- Could examine proppant flow back at production well - Scaling from Collab to Forge?	- Would need high temperature proppants. - Cost concerns
Multiple boreholes injection/production wells	- Would allow for more flow control within fracture	- Uncertainty of number of well needed and locations	- Depends on results of Experiments 1-2	- May not be applicable due to cost
Oscillatory/Pulse Flow	- Possible in situ particle control	- Unclear if particle transport in a EGS fracture is a major concern	- Do not have monitoring capability at Collab to image particle movement within fracture	- Might be best in natural fracture zones
Injection of diverters/plugging agents	- Possible method of controlling preferential flow in a fracture	- Potential plugging of all pathways in the fracture - Current geothermal diverters are temporary		- Role more likely in fracturing less in flow control

4.1 High Relevant Methods

Eight potential methods appear to be most appropriate for evaluation for Collab Experiment 3.

4.1.1 Fracture Initiation

Wells for O&G production and potentially for EGS development are often drilling in the direction of minimal principal stress so fractures propagate orthogonal to the wellbore. However, in initiating a hydraulic fracture from a borehole, the pressurization of the hole has minimal effect on the near wellbore stress in the axial direction of the borehole. As such, wells drilling in the minimum stress direction will generally initiate along the borehole.

To avoid this and the associated near wellbore tortuosity it is possible to seed a fracture by creating a stress concentration at the borehole wall. One way to do this, as implemented in the Experiment 1 of

Collab is the cutting of a circumferential notch in the borehole wall (Figure 4). The intent of the notch is to allow fractures to initiate in a direction of what is believed to be perpendicular to the minimal principal stress direction. Controlling fracture initiation direction is important for minimize near wellbore tortuosity and improve near wellbore flow properties as well simplifying analyses.

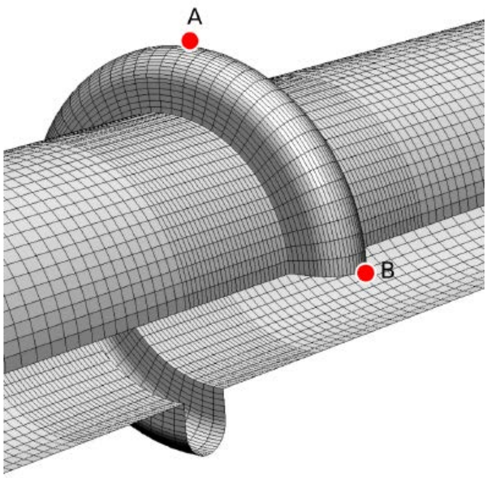


Figure 4. Grid meshing of a notch in a well bore (from LLNL) and picture of a test notch (from SNL)..

4.1.2 Slickwater/low viscosity hydraulic fracturing

In the 1950's, river water was used for hydraulic fracturing purposes. This practice of using low viscosity fluids fell out of favor in lieu of more viscous gels in the 1960's and 1970's but was revitalized with the advent of unconventional shale reservoirs in the early 2000's. The term "slickwater" is used to describe a set of fracturing fluids that are low viscosity and range in composition from just fresh water to brine water (generally KCl water) to water with polyacrylamide (PA) polymer and surfactants added. The viscosity of these fluid systems range from ~1-2 cp, which means that proppant transport occurs via velocity and not viscosity. These fluids generate minimal fracture widths and more complexity than viscous fluids due to their ability to easier penetrate pre-existing weaknesses (i.e. natural fractures).

Slickwater generates length quickly in hydraulic fracturing scenarios with minimal height generation. In the 10 m testing scenario, the fluid has the potential for generating complex fractures from a map view standpoint and reactivating and connecting pre-existing natural fractures. However, the fluid will likely connect quickly to the offset production well, minimizing generated fracture complexity and will not generate significant height. Surface area will be limited in the vertical direction, but could exist from a complexity standpoint. Due to the lack of viscosity, proppant loading will be lower compared to viscous fluids, and the resulting fracture will therefore have lower resulting conductivity. Additionally, proppant flowback may be a concern.

4.1.3 Viscous gel hydraulic fracturing

Hydraulic fracturing gels can be designed to generate viscosities range from 5 cp to over 2000 cp. These viscous fluids can transport significantly higher volumes of proppant, resulting in higher overall fracture conductivities. Unlike low viscosity, slickwater fluid systems, these more viscous systems tend to generate more planar-type fractures with less complexity. They also tend to generate more height than slickwater systems under the same stress/rock property scenarios. The viscosity, and reduction of such, is controlled by the addition of gel and associated chemicals. Even when the chemicals work perfectly to reduce the viscosity, there is some gel residual that remains and fills and damages the conductivity in the proppant pack.

In the 10 m testing scenario, a viscous fluid has more of an opportunity than slickwater to generate a single planar fracture with significantly more height and likely more surface area. Additionally, the viscous gel will be able to carry and place higher proppant volumes, thus producing a higher resulting conductivity. In EGS systems, the high temperatures will make generating a suitable gel system more challenging than in oil and gas applications, however, this higher temperature will help to break and clean-up the gel resulting in higher permeability.

4.1.4 Simultaneous multiple well fracturing

Two dimensional discrete element method (DEM) modeling results suggest that simultaneous fracturing at both the injection and the production well could result in connected fractures. The stress field at the tip of the fractures is such that the fractures would attract each other resulting in a single fracture connecting the two wells. More modeling would be needed to assess sensitivity to the length scale to establish such a connection as well as the alignment of the initiation of the two fractures.

4.1.5 Energetic Fracturing

Unlike hydraulic fracturing, energetic fracturing can create fractures at the wellbore and to some distance into the formation that are not coincident with principle stress directions. For this to occur, pressurization rates and maximum pressures need to be tailored to be high enough to “ignore” or overcome the in situ stress but controlled to not create formation damage that will inhibit flow from and to the well. This can be accomplished but using energetic system at react at rates higher simple deflagration and lower than common high explosives (Figure 5).

Figure 5. Borehole video log of a fracture created using controlled pressure fracturing (from SNL).

Energetic fracturing may have a role at Collab, however one would need to determine the scaling necessary (charge loading, diameters, length, etc.) to effectively emulate how energetic fracturing would be applied to scales larger than the 10 m scale of Collab.

4.1.6 Injection of diverters/plugging agents

The permeability of the Poorman formation was calculated using the Hvorslev (1951) method for point piezometer and evaluating the water level response form the kISMIT boreholes. Both K2 and K5 boreholes, the permeability was calculated to be approximately 10^{-18} m2. For boreholes K1 and K4, where the data was extrapolated, the permeability is approximately on order of magnitude less, $3x10^{-19}$ m2. If this data is representative for the geologic conditions at the Collab Experiment 1 site, these results suggest that leakoff from the hydraulic fracture could be quite large for during stimulation and possible during flow testing and may provide an opportunity to address circulation fluid loss.

Although the use of FLAs to control water loss during the fracturing process in both petroleum and EGS sites will likely be similar, controlling water loss during operation of the two systems will require different strategies. The fracture fluid pressure in petroleum systems are operated at pressures less than the reservoir fluid pressures. EGS system will likely operate at pressure higher that the surrounding reservoir pressures and will have high fracture flow velocities for extend periods of time under high temperature conditions. Some studies funded by the GTO have examined fluid losses during EGS stimulations but have not attempted to address fluid loss during operation. One challenge of injecting particulates is the selective plugging of non-desirable fractures while maintaining the fracture conductivity of desirable fractures.

4.1.7 Borehole zonal isolation and flow control

Engineering borehole flow control between fractures provides an opportunity for validation of models over a wider range of flow conditions. Both passive and active systems already exist for fossil energy applications and modified implementations could be considered for this project.

Passive flow control largely consists of static elements in the system that choke the flow rate and force re-distribution of fluid into multiple fractures. This is most readily explained by considering a simple scenario with two fractures intersecting a cased borehole. We assume that where each fracture intersects the borehole we have a connection into the wellbore with some frictional losses between the pressure in the borehole and the pressure in the fracture (let us call these loses perforation friction and they may differ for each fracture location). If the pressure losses within the borehole are low and the perforation friction is also low, then small differences between the conductivity of the two fractures will result in the majority of the fluid being diverted into the more conductive of the two fractures. Similarly, if the borehole pressure losses are high, then the upstream fracture will take the bulk of the fluid. Conversely, if the perforation friction pressure losses are significant compared with the borehole or fracture pressure losses, then it can be shown that as the perforation friction increases, the portioning of fluid between the two fractures equalize. In oil and gas applications, completion designers often attempt to manage the perforation friction associated with each fracture by increasing or decreasing the number of perforations in the casing (more perforations for reduced friction). Although the effectiveness of this approach is disputed by some, practitioners attempt to compensate for the different fracture conductivities by tuning the perforation friction using this approach. This practice is known as “limited entry design” or “limited entry treatment” and typically seeks to divert equal quantities of fluid into each fracture.

Active flow control, where so-called “intelligent completions” are utilized have also been developed. With this approach, mechanisms are deployed in the wellbore to allow active control of the flow between the borehole and the fractures at designated locations. The specific approach utilized varies widely depending upon the vendor. The most sophisticated intelligent completions incorporate permanent downhole sensors and surface-controlled downhole flow control valves, enabling you to monitor, evaluate, and actively manage production (or injection) in real time without well interventions. If you have short boreholes and multiple pumps available, it is conceivable that active control can be achieved through multiple packed-off zones operated by separate pumps with a pass through. It is also possible to achieve active flow control with a single pump through controllable chokes, sliding sleeves, etc. that effectively provide a controllable, variable equivalent of perforation friction that can be adjusted to achieve the desired flow diversion.

4.1.8 Multiple boreholes flow control

Current Experiment 1 and 2 designs suggest a single injection and production well for the flow experiments. Multiple injection and production wells would allow for a higher degree of freedom to conduct flow experiments to characterize the fracture and allow for more through model validation. The wells could also serve as monitoring wells for pressure monitoring, aperture measurements, and as ports for fluid sampling.

4.2 Relevant Methods

Four methods are suggested for consideration although they may lack scaleablity or high need at FORGE.

4.2.1 Injection of proppants

The use of proppants to create better well injectivity/productivity has been examined by the GTO. Between the years of 1979 and 1984 DOE/GTO sponsored the Geothermal Reservoir Well Stimulation Program (GRWSP). Through this program the GRSWP performed 8 field tests. Six of these tests at Raft River, East Mesa, and Baca used proppants. Only the stimulations conducted in sedimentary systems were 'successful', stimulations in fractured systems did not meet project objectives. Proppants used in these tests included sand, resin coated sand and bauxite.

During the past 40 years, a variety of new proppants have been developed with many claims of better performance. Claims include; better transport, improved crush resistance, stronger, fusion technology, more spherical, alternative shapes, web coating and flow-channeling capabilities. Most of these proppant have not been adequately evaluated as to their longevity and fracture permeability performance by independent researchers to understand there potential benefits in EGS reservoir conditions. Experiment 3 along with high temperature laboratory testing could evaluate proppant manufacture's improvement claims.

4.2.2 Short-Interval Flexible-Packer Stimulation

To create a fracture that is perpendicular to the borehole, the configuration of the straddle packer system should be considered. The injection subassembly (sub) between packers in a straddle packer system can be long compared to the diameter of the borehole, and may be relatively stiff (Figure 6). From a borehole oriented parallel to the minimum principal stress, research has shown that, in the absence of proper perforation or notching, the stimulated fractures tend to initiate parallel to the borehole and then twist to propagate in the direction of the maximum principal stress, and that shorter lengths (on the order of less than 4 borehole diameters) between packers tend to reduce this effect (El Rabaa, 1989, Abass et al., 1996). The stiffness of the sub is also thought to impact the fracturing, as it holds the two packers in the same relative location. Since it is desired to open the borehole-perpendicular fracture, the stiff sub may hinder the opening by holding the rock faces together. The fundamental idea behind the short-interval flexible-packer stimulation method is to reduce the tendency to induce a borehole-parallel fracture by shortening the sub length to much less than four times the well diameters and reducing the stiffness thus not hindering the fracture opening perpendicular to the borehole.

Figure 6. Straddle packer. The two black rubber regions are inflated to set the packers in a borehole (DuraFRAC Mini, courtesy of IPI).

4.2.3 Fracturing at the toe

It is reported that fractures can be initiated perpendicular to the borehole axis if a short section of the well is isolated at the toe of the well. The end of the hole at the toe creates a stress concertation that enables initiation of a fracture perpendicular to the axis of the hole.

4.2.4 Oscillatory/Pulse Flow

Oscillating flow has been proposed by some as a means to improve average fracture conductivity (note that fracture conductivity can decrease with time using steady state methods) and overall flow distribution through fractures. The introduction of pressure/flow changes has the potential to overcome particulate flow blockages, multi-phase permeability reduction effects, and encourage flow through smaller aperture pathways. These benefits are poorly understood at this time and are largely unproven at the field scale.

4.3 Low Relevant Methods

Nine methods appear to have the lease relevance to Collab and FORGE either due to conditions at the potential Collab sites, low technology development level, or relevance to FORGE.

4.3.1 Oscillatory/pulse fracturing

Novel methods for stimulating fracture permeability via unsteady-state fluid injection have been proposed and some of these methods have been field tested. Unsteady injection methods may promote complex fracture network creation by combining hydraulic fracturing, shear stimulation, and re-fracturing effects into a single stimulation treatment. The scale of the Collab site would likely be too small to examine these effects.

4.3.2 Thermal stress alteration fracture

The SURF or any other site we examined does not have sufficient temperature to examine fracture thermal drawdown effects on subsequent fracturing.

4.3.3 Acid injection or fracturing

Acid injection (e.g., HCl, H2SO4, or HF) can be used to improve flow to and from oil and gas wells in carbonate rich formations. The Poorman formation at SURF is carbonate rich. This method enhances permeability by chemically etching wormholes through the rock which, if done properly, can increase permeability. The method is most effective near the injection point in the well and can help remediate near-wellbore tortuosity. Environmental health and safety concerns are significant with using acid and not all acid is always spent in reaction with the carbonate. Unlikely that acid fracturing would be used at a FORGE site.

4.3.4 Non-water

Using carbon dioxide instead of water as an EGS stimulation and working fluid has been proposed and investigated by some projects. CO2 is a low viscosity supercritical fluid at EGS conditions that can be passed through turbines at the surface to generate electricity. Using CO2 as a fracturing and working fluid is expected to produce different fracture stimulation geometry and also serves the role of CO2 sequestration. CO2 will likely not be used as a stimulation/working fluid at FORGE or initial EGS sites.

4.3.5 PNNL’s SimuFrac fluids

PNNL has developed a fracturing solution, comprised of a polymer that can expand up to 2.5 times its original volume and is triggered by a pH drop associated with the presence of CO2. This technology would likely require more laboratory and modeling evaluations prior to testing at Collab.

4.3.6 Mechanical impulse fracturing

A proposed method for fracture stimulation utilizing controlled ultra-high pressure impulses to stimulate a larger fracture network and promote fracture shearing for self-propping. Experiments suggest that this method can be a useful tool for enhancing injector-producer hydraulic communication but field studies have not yet been conducted. Scale of Collab site may not be appropriate for testing.

4.3.7 Thermal fracturing

The SURF or any other site we examined does not have sufficient temperature to examine thermal fracturing.

4.3.8 Long term injection

The SURF or any other site we examined does not have sufficient temperature to examine long term thermal contraction effects.

4.3.9 Electro-fracturing

Not likely to be used in initial FORGE and EGS sites.

5. Summary

This report lists twenty one potential methods under consideration for testing as part of Collab Experiment 3. The potential methods have been categorized as; Fracture Initiation, Stimulation Fluids, Stimulation Methods and Flow Control. The categories have been further divided into three general groups (e.g. high, medium, low) based on applicability to the scale of measurement at Collab (~10 meter) and it’s applicably to FORGE. The highest relevant methods (not necessary in order) are:

1. fracture initiation within the borehole,
2. use of slickwater fracturing fluids
3. use of viscous fracturing fluids,
4. simultaneous stimulation of multiple wells,
5. use of energetic fluids to initiate larger fractures or connect a borehole to existing fractures,
6. injection of diverters to control short circuits and working fluid loss,
7. testing of borehole isolation techniques to control water flow pathways in the reservoir,
8. use of multiple injection and production wells to characterize a fracture.

Fractures created in Experiments 1 and 2 offer the opportunity to test engineering solutions to issues encountered in the stimulation process or during the fracture flow testing. An advantage of using these sites is that there would be a wealth of baseline characterization data for the site, and the borehole monitoring system and experimental infrastructure is already established and could possibly be reused.

This list should be considered preliminary due to the scheduling of Collab Experiments 1 and 2 and the due date of this report as well as the need for preliminary modeling to assess each of the proposed methods effectiveness.

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Appendix 1. Review of Other Subsurface Research Facilities

ASPO

In June, 2015, a series of hydraulic fracturing tests were conducted at Äspö (Zhang et al., 2017). The goal of the tests was to determine how aspects of the injection protocol can influence the generation of AE. The experiments employed pumping rates between 0.01 and 0.08 L/s with a typical total volume injected of 10 liters (see Zhang et al. 2017, Table 3). The AE observations performed during these tests indicate the fractures have a radius of approximately 6 m (see Zang 2017, Figure 8).

Bad Urach

Not all stimulations resulted in a permanent increase in fracture permeability. Research borehole Urach 3 is located in the east of the Black Forest Mountains. Analysis of numerous slug and continuous injection these tests suggest that the massive hydraulic stimulation tests was in an extensively fracture system illustrating a log-log linear relationship between the specific pressure and the injection rate. (Note that the specific pressure is the injection pressure over the injection rate, ie the inverse of what is commonly called the injectivity of a well.) The negative correlation between the specific pressure and the injection rate suggests a widening of the fractures with increasing injection rate/pressure. The massive hydraulic stimulation does not seem to cause a permanent increase of the basement's permeability. After the borehole pressure is released, the fracture plane adopted its original "spacing", meaning the crystalline basement returned to its former transmissivity (Stober, 2011)

Basel, Switzerland

Häring (et al, 2008) summarized the Deep Heat Mining Project at Basel, Switzerland. The Basel project used a vertical borehole that intersected a sub-vertical fracture system below the casing shoe at a depth of about 4400 m. The hydraulic stimulation lead to a large disk shaped reservoir with a vertical and horizontal extend of about 1 km each and a thickness of about 50 to 100 m. It was expected that permeability would increase by shearing of natural fractures which are approximately vertical and oriented within a sector of around +/- 30° from the direction of the largest horizontal stress. No pressure-limiting behavior was observed, suggesting that "formation fracturing" did not occur at the casing shoe. The basement rock was stimulated by a massive injection of 11,570 m3 of river water over 6 days. The maximum injection pressure applied during stimulation did not exceed the magnitude of Shmin.

Because the operation was suspended due to seismic concerns, no conclusive assessment of the efficiency of the stimulation. However, estimates are that the fracture transmissibility had increased by a factor of approximately 400 and that this enhancement proved irreversible throughout the bleed-off phase.

One recommendation from this project was rather than a single massive hydraulic injection, injecting a limited fluid volume over a short time period, venting the reservoir and subsequently monitoring the resulting events, "nudge and let it grow" procedure could be applied repeatedly; a strategy that may be somewhat time-consuming but might help to minimize perceptible induced events in EGS.

Bouillante, Guadeloupe

BO-4 is a vertical production well and was initially classified as a low producer. Cold sea water injection (~8000 m^3) in August 1998 to enhance thermal cracking and decreased well skin effect was accredited in increasing production by 50%. (Tulinius, et al., 2000)

Soultz

Soultz was located in an extensional geologic regime and was able to sustain circulation flow rates up to 25 kg/s. Due to the extensional geologic, Soultz also was able to keep the overall pressure lower by pumping the production well. At the Soultz test site, an important relationship was found between the injection rate during stimulation and the productivity of the well after stimulation (Jung and Weidler, 2000). The productivity of the wells appears to increase linearly with the injection rate during stimulation.

Fenton Hill, USA

The Hot Dry Rock test connected two wells via hydraulically fracturing. Multiple circulation experiments were carried out over the course of a few years, ending with a 9 month circulation test. One of the biggest lessons learned was not to assume the stress orientation at depth and that rocks fractures in different directions than expected.

Rosemanowes, Britain

At Rosemanowes, high flow rates were obtained but short circuiting and continued reservoir growth became an issue. Wells stimulated by explosive fracturing followed by hydraulic stimulation resulted in creating a reservoir that continuously grew downwards during circulation testing. Similar to Fenton Hill, the fractures grow in the predicted direction. The system exhibited water losses up to 70% and had a high impedance to flow. A new production well was drilled in the reservoir and flows up to 25 kg/s could be maintained. The new well was stimulated with viscous gel with proppant to decrease water loss and the high impedance. Although the treatment was successful in reducing these issues, short circuiting became a more acute problem. Analysis of the data suggests that the reservoir fractured along pre-existing joints and not creating hydraulic fractures. Stimulation was accredited for mostly near well improvements.

Hijiori, Japan

In an experimental and geologic field similar to Fenton Hill, Hijiori was not successful in create a productive reservoir. The stimulations failed to effectively connect the production wells to the injection well. Water loss was in excess of 70%. One of their findings was that it was difficult to control water flow in multiple reservoirs and multiple wells simultaneously. They also concluded that multiple wells were able to recover more of the injected water than a simple dipole system (~70% compared to ~30%).

Ogachi, Japan

In a subsequent EGS test in Japan, Ogachi hydraulically fractured a well then drill additional wells into the fractured zone. Similar to Hijiori, a poor connection was established between the production and injection wells. Water losses were as high as 90%. Circulation water tests injected water from 8 to 17 kg/s while the production well never produced more the 2 kg/s.

Cooper Basin, Australia

The world’s largest EGS project in Australia’s Cooper Basin recently completed a successful 6-year ‘‘proof of concept’’ phase, during which commercial-scale reservoirs and wells were successfully fractured and drilled, achieving desired production flows. (Stephens and Jiusto, 2009). The system experienced well failures but geology and stress were amenable to reservoir creation.

Fjällbacka, Sweden

Fjällbacka attempted to connect two wells at 500m with a horizontal fracture in Bohus granite during the mid-80s to mid-90s using hydraulic fracturing. Microseismic data suggest the hydraulic fracturing resulted in shearing of existing horizontal fractures. Fracture transmissivity increase approximately 100x to 8E-6 m2/s for a 30m section. Production flow rate increased to 51% of the injection rate by the end of a 40 circulation test. Information was obtained from Wallroth et al. 1999.

Grimsel, Sweden

The Grimsel Test Site (GTS) located in the Swiss Alps was established in 1984 as a center for underground Research and Development (R&D) supporting a wide range of research projects on the geological disposal of radioactive waste. As part of this center, the In-situ Stimulation & Circulation

Experiment is to understand of geomechanical processes underpinning permeability creation during hydraulic stimulation and related induced seismicity. This work is presently ongoing with stimulation, hydraulic multi-packer and tracer testing.

Appendix 2. GTO EGS Demonstration Projects.

EGS sites that may fall along the continuum of EGS: ranging from ubiquitous "green fields," to the outskirts of existing hydrothermal fields, and finally to unproductive portions within operational hydrothermal fields. The EGS demo Program tended to fund projects mostly in the third category; unproductive portions within operating hydrothermal fields (DOE 2008). The following is a brief summary of those projects with much information from Ziagos et al. 2013.

Desert Peak, Nevada

Desert Peak wells were stimulated using a number of techniques; low volume injections, chemicals, high volume. The injectivity of the well increase by 175-fold from 0.01 to 2.1 gpm/psi. All stimulation techniques increased the well injectivity to some extent. The chemical stimulation increased permeability but at the expense of well bore stability. The project successful stimulated the injectivity of a well to commercial levels (source https://energy.gov/eere/geothermal/downloads/desert-peak-egs-project).

Brady's Hot Springs, Nevada

Three zones of well 15-12 were stimulated as part of the GTO funded project. Two zones are believed to have stimulated natural fractures and have an injectivity index of ~.5 gpm/psi. The stimulation pumping stages lasted approximately 10 hours. Spinner survey suggests water will leave the well near two zones that were stimulated. A final report is due to GTO at the end of 2017. (source: https://energy.gov/eere/geothermal/downloads/gto-peer-review-2017)

The Geysers, California

The overall goal of the demonstration project is to "Enhance the permeability of hot, low permeability rock by injecting cool water at low pressures to 'gently stimulate' thermal fracturing processes ." They attempted stepwise injection of water to encourage thermal contraction and promote shearing of the natural fractures. Water was injected into a rock reservoir that had temperature up to 400C and is believed to promoted micro thermofracturing. Results suggest an additional 5 MW of production was created. (source https://energy.gov/eere/geothermal/downloads/enhanced-geothermal-system-egs-fact-sheet-0)

Newberry Volcano,

At Newberry, a well was stimulated by injecting cold fluid for 40 days. Thermal-degradable zonal isolation materials were used to direct the stimulation toward less permeable zones. EGS reservoir created with volume up to 1.5 km^3. Claim the injectivity increases while conducting cycling injection pressure. (source https://energy.gov/eere/geothermal/downloads/newberry-egs-demonstration)

Raft River, Idaho

The Raft River EGS Demonstration Project consisted of three hydraulic stimulations of RRG-9 followed by a long continuous injection of recycled brine into the well over a period of approximately 1400 days. Changes in injectivity immediately following high-flow rate tests suggest that hydro shearing has altered the near-well permeability structure, while pressure response during those tests indicates that near-well permeability is relatively homogeneous and low but that the well is near, but not well connected to a zone of higher transmissivity. Long-term changes in injectivity are believed to reflect propagation of the cool water injection (Plummer et.al, 2015). Tracer tests revealed that fluid flow patterns evolved over time along the injection/production pathway with tracer breaking through progressively earlier and to more wells over the duration of the testing (Rose et.al. 2017).

Appendix 3 Currently Funded GTO EGS R&D Projects

GTO is currently funding 12 EGS R&D projects (see Table 3.1 for GTO descriptions of each project).

All these funded projects can be considered subsurface characterization projects and can be generally characterized to: 1) designed to interrogate the fracture density, size, and dimension, 2) characterize the fluid flow patterns in the fracture, and 3) assess changes in the fluid flow patterns in the subsurface. A majority of the PIs are from Universities. Some of these funded projects may be mature enough to be incorporated into Experiment 3.

Table 3.1 Current GTO EGS R&D Projects, (from https://energy.gov/eere/geothermal/downloads/integrated-egs-rd-foa-selections, 08/30/2017)

Array Information Technology will develop an integrated approach to assess the flow of injected fluid during EGS resource development. Array will monitor the system prior and during EGS injection, evaluate the fracture density and dimensions, and determine the fluid flow velocity in the activated fracture network.
California State University Long Beach plans to evaluate hydraulic connectivity among geothermal wells using Periodic Hydraulic Testing (PHT). The principal is to create a pressure signal in one well and observe the responding pressure signals in one or more observation wells to assess the permeability and storage of the fracture network that connects the two wells.
Cornell University will develop and test a chemical tracer procedure for modeling reservoir structure and predicting EGS thermal lifetime. If successful, this will provide reservoir operators with the ability to evaluate proposed reservoir management practices and to quantify the probability of successful deployment, including cost.
Lawrence Berkeley National Laboratory plans to develop a three dimensional fluid transport model using radon in order to better characterize fractures in geothermal reservoirs. LBNL will use the amount of radon in the water to calculate the size of the fracture the water travels through, a critical EGS parameter.
Lawrence Berkeley National Laboratory plans to model and simulate an integrated technology using geophysical methods in combination with injection of carbon dioxide for purposed of well monitoring. The technology is designed to characterize fractured geothermal systems.
Los Alamos National Laboratory will develop high-precision characterization techniques to model fluid-flow pathways in EGS reservoirs. This research will provide high-resolution, high-accuracy 3D models, and produce high-resolution images of fracture zones in EGS reservoirs. If successful, this research will provide a new technology for mapping and characterizing fluid-flow pathways in EGS reservoirs.
Pennsylvania State University will explore ways to assess both the characteristics and evolving state of EGS reservoirs prior to stimulation and during production. The project will help scientists analyze the permeability of reservoir fracture networks in order to understand evolving flow structure and to engineer thermal recovery systems.
Pennsylvania State University will focus on the processes governing fracture flow and energy production in EGS reservoirs and examine methods to manage and predict changes in permeability over their lifetimes. This will be accomplished by measuring properties of reservoir rocks to study the mechanisms of fluid-induced permeability and to develop acoustic methods to image fracture characteristics.
Sandia National Laboratories will develop a system of nanoparticle-based chemical tags for EGS reservoirs. The gradual release of the unique tags will mark both the location of the reservoir and flow

rates for above-ground assessment. This previously-unavailable information will provide engineers the ability to closely monitor many subsurface flows simultaneously, leading to production efficiencies, and will provide for longer term monitoring without interfering with active wells.
University of Nevada, Reno will use a technique to detect interference between pairs of seismic signals in order to gain useful information about the subsurface. Existing and newly acquired seismic survey data will be used to compare data from this cost-effective, non-invasive, seismic exploration method with data from a comprehensive geoscience study of the geothermal system in Dixie Valley, Nevada. This proposed technology has the potential to enhance the ability to characterize subsurface fracture, stress and other physical reservoir properties at a variety of geothermal fields.
University of Oklahoma will integrate several techniques for characterizing full-sized EGS reservoirs under realistic stress and temperature conditions, including simultaneous monitoring of acoustic emissions, fluid flow tracers, and changes in reservoir pore pressure and fluid/rock temperature. The proposed work will provide essential data and information to understand induced fractures, and will help improve reservoir performance.
University of Wisconsin-Madison will assess a technology for characterizing and monitoring changes in the mechanical properties of rock in an EGS reservoir in three dimensions. The integrated technology will analyze data including seismic waveforms, ground deformation, specialized radar, and comparisons of well pressure, flow, and temperature to characterize the reservoir.