PROCEEDINGS, 43rd Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 12-14, 2018
SGP-TR-213

Potential Experimental Topics for EGS Collab Experiment 3

Earl Mattson[1], Douglas Blankenship[2], Bud Johnston[3], Luke Frash[4], Joe Morris[5], Timothy Kneafsey[6], Jennifer Miskimins[7] and the Collab Team

[1]Idaho National Laboratory, [2]Sandia National Laboratories, [3]National Renewable Energy Laboratory, [4]Los Alamos National Laboratory, [5]Lawrence Livermore National Laboratory, [6]Lawrence Berkeley National Laboratory, [7]Colorado School of Mines

Earl.Mattson@inl.gov

Keywords: EGS, Collab, FORGE, Hydraulic Fracturing

ABSTRACT

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 (~10 m) scale for the validation of thermal-hydrological-mechanical-chemical modeling approaches as well as novel monitoring tools. The first two EGS Experiments 1 and 2 are planned be performed under different stress/fracture conditions, and will evaluate different stimulation processes: Experiment 1 will focus on hydrofracturing of a competent rock mass, while Experiment 2 will concentrate on hydroshearing of a rock mass that contains natural fractures. Experiment 3 is scheduled to begin in 2019 and will build off the lessons learned in Experiments 1 and 2 and will investigate alternate stimulation and operation methods to improve heat extraction in an EGS reservoir. This paper evaluates potential experiments that could potentially be conducted in Experiment 3.

The two technical parameters defining energy extracted from EGS reservoirs with the highest economic uncertainty and risk are the production well flow rates and the reservoir thermal drawdown rate. A review of historical and currently on-going EGS studies has identified that over ½ of the projects have identified heat extraction challenges during their operation associated with these two parameters as well as some additional secondary issues. At present, no EGS reservoir has continuously produced flow rates on the order of 80 kg/s. Short circuiting (i.e. early thermal breakthrough) has been identified in numerous cases. In addition, working fluid loss (i.e. the difference between the injected fluid mass and the extracted fluid mass as compared to the injected mass) has been as high as 90%. Finally, the engineering aspects of operating a true EGS multi-fracture reservoir such as repairing/modifying fractures and controlling working fluid fluxes within multiple fractures for the effective EGS fracture management has not been sufficiently studied. To examine issues such as these, EGS Collab Experiment 3 may be conducted in the testbeds prepared for Experiments 1 and 2 by improving the previously performed stimulations, or conducted at a new site performing new stimulations with an alternate method. Potential experiments may include using different stimulation and working fluids, evaluating different stimulation methods, using proppants to enhance permeability, and other high-risk high-reward methods that can be evaluated at the 10-m scale environment.

1. INTRODUCTION

Recently, a number of authors (e.g. Tenzer, 2001, Tester et al. 2006, Breede et al. 2013, Grant 2016, Lu 2018) have reviewed the state-of-the-art of Enhanced Geothermal Systems (EGS) located throughout the world. Tenzer (2001) chronologically listed the technical milestones for the development of the Hot Dry Rock (HDR) systems. He then described 10 projects, listed by countries, and their challenges and achievements. Tester and others (2006), in the commonly referred to as the MIT report, summarizes 16 EGS projects and divided the projects into two groups; 6 'major' and 10 'smaller' projects. The 6 major EGS projects include Fenton Hill, Rosemanowes, Soultz, Cooper Basin, Hijiori and Ogachi. The smaller projects include Coso, Desert Peak, Glass Mountain/Geysers-Clear Lake, Fjallbacka, Falkenberg, Bad Urach, Basel, Geneva, Le Mayet, and Horstberg. Breede and others (2013) identified 31 EGS projects in

---

The Collab Team includes; J. Ajo-Franklin, S.J. Bauer, T. Baumgartner, K. Beckers, D. Blankenship, A. Bonneville, L. Boyd, S.T. Brown, J.A. Burghardt, T. Chen, Y. Chen, K. Condon, P.J. Cook, P.F. Dobson, T. Doe, C.A. Doughty, D. Elsworth, J. Feldman, A. Foris, L.P. Frash, Z. Frone, P. Fu, K. Gao, A. Ghassemi, H. Gudmundsdottir, Y. Guglielmi, G. Guthrie, B. Haimson, A. Hawkins, J. Heise, C.G. Herrick, M. Horn, R.N. Horne, J. Horner, M. Hu, H. Huang, L. Huang, K. Im, M. Ingraham, T.C. Johnson, B. Johnston, S. Karra, K. Kim, D.K. King, T. Kneafsey, H. Knox, J. Knox, D. Kumar, K. Kutun, M. Lee, K. Li, R. Lopez, M. Maceira, N. Makedonska, C. Marone, E. Mattson, M.W. McClure, J. McLennan, T. McLing, R.J. Mellors, E. Metcalfe, J. Miskimins, J.P. Morris, S. Nakagawa, G. Neupane, G. Newman, A. Nieto, C.M. Oldenburg, W. Pan, R. Pawar, P. Petrov, B. Pietzyk, R. Podgorney, Y. Polsky, S. Porse, S. Richard, M. Robertson, W. Roggenthen J. Rutqvist, D. Ryders, H. Santos-Villalobos, P. Schwering, V. Sesetty, A. Singh, M.M. Smith, H. Sone, C.E. Strickland, J. Su, C. Ulrich, A. Vachaparampil ,C.A. Valladao, W. Vandermeer, G. Vandine, D. Vardiman, V.R.. Vermeul, J.L. Wagoner, H.F. Wang, J. Weers, J. White, M.D. White, P. Winterfeld, T. Wood, H. Wu, Y.S. Wu, Y. Wu, Y. Zhang, Y.Q. Zhang, J. Zhou, Q. Zhou, M.D. Zoback

their review. They divided the EGS projects into 4 groups: 1) eight under development projects but not producing electricity, 2) fourteen ongoing projects producing electricity, 3) six experimental projects without power generation, 4) and three abandoned (on-hold) projects. Grant (2016) describes 6 Hot Dry Rock (HDR)/EGS projects in terms of their performance indicators (reservoir impendence, recovery factor, and tracer-sweep volume. Olasolo and other (2016) provided a general overview of developing an EGS facility from siting to financial considerations. Most recently, Lu (2018) identifies 18 '*significant*' EGS sites, which appears to be based on those that produced electrical power (see his Table 1).

The choice of the number of EGS projects to discuss appears to be determined by: what sites were active at the time of publication, the definition the authors chose for what constitutes an EGS project, as well as the overall purpose of the paper. For example, Cappetti (et al. 1997) used a hot dry rock definition "*Any system where injection is necessary to extract the heat at a commercial rate for a prolonged period*" to suggest that the Lardarello geothermal site could be classified as a HDR/EGS system. The definition of what constitutes an EGS project varies among authors/institutes (e.g. see Breede et al. 2013 for 4 examples).

Table 1 lists EGS projects that have been identified in 5 review papers as well as some experimental subsurface testing facilities examining rock stress and hydraulic fracturing. The time listed in Table 1 for when a project begins should be view as approximate. Dates listed by authors depended on the definition used by various authors. Some used a date when a site was being considered, others when the first exploratory wells were drilled, and still others used the date of the stimulation to define the start of the EGS project.

2. MAJOR CHALLENGES FOR EGS

Based on the review of EGS projects and their individual challenges, a number of general challenges have been identified.

2.1 Obtain Sufficient Flow Rates

Well productivity remains the greatest technological challenge for the commercialization of EGS (DOE, 2008). Commercialization production rates has been defined somewhere in the range of 50 to 100 kg/s (Ziagos et.al. 2013). The MIT report (Tester et al. 2006) reported this value as 85 kg/s. Of the EGS projects to date, Soultz has exceeded other projects with a maximum well productivity of about 25 kg/s.

Not all hydraulic stimulations have resulted in a permanent change in the reservoir's permeability. Stober (2011) states that after the hydraulic stimulation at Bad Urach when the borehole pressure was released, the reservoir returned to its former transmissivity. In contrast, sites like Fenton Hill concluded that the effects of reservoir stimulation persist over time (Keller et al., 2016).

Due to diverging/converging flow pathways, flow impedance is often the greatest near the injection and production wells. Injection wells often obtain a benefit of thermal contraction/fracturing of the reservoir due to the cool/cold water injection. EGS demonstration projects at Raft River and the Geysers have documented that the injectivity at injection wells increased over time. However, Keller (et al. 2016) states flow impedance was greatest at the production well for the Fenton Hill project. If the fractures near a production well are pressure supported, the low fluid pressure near the production well would result in the smallest apertures and therefore a zone of large impedance. Developing methodologies to enhance the fracture permeability near production wells will likely be needed to obtain high flow rates.

2.2 Controlling Early Thermal Breakthrough

The longest period of continuous performance of an EGS demonstration project was at Rosemanowes. Fluids were circulated at Rosemanowes for three years, during which production temperatures fell from 80 to 55°C (DOE, 2008), which suggests 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 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 Minimizing Excess Fluid Losses

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 lose 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 to 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 include 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). However, these petroleum fluid loss control methods may not be applicable to EGS sites.

Often associated with fluid loss is reservoir growth. EGS projects such as Soultz have achieved bounded reservoir growth via hydraulically connecting wells to the natural fractured system in a fairly well confined system. However, tests conducted at other EGS projects such as Rosemanowes have illustrated that due to the high injection and extraction well pressures; unconfined reservoir growth can be an issue. One of Fenton Hill's biggest lessons learned was not to assume the stress orientation at depth and that rocks fracture in different directions than expected.

Table 1. List of EGS projects obtained by a literature search.

EGS Project[a]	Beginning of Project (Years)[b]	Reservoir Rock[e]	EGS Identified					Comments
			Tenzer (2001)	MIT Report (2006)[c] (Tester et al.)	Breede et al. (2013)[d]	Grant (2016)	Lu (2018)	
Fenton Hill Phase 1 & 2	1974	I	X	M	E	X	X	Hydraulic – natural fracture system
Falkenberg	1975/1977	I	X	S	E			Hydraulic fracturing at 500 m depth. Investigated fracture width and fluid pressure.
Rosemanowes	1975/1977	I	X	M	E	X	X	Majority of the stimulation was shear mode of natural fractures.
Le Mayet	1976	I	X	S	U			Used borehole packers to stimulate single fractures.
Bad Urach	1977/2006	M	X	S	A			Abandonment – test extraction using a single borehole
Lardarello	1979	M			G			Water injection to increase steam production.
Bruchsal	1983	S			G			Natural fracture system
Neustadt-Glewe	1984	S			G			A low enthalpy system
Grimsel	1984							Experiment was designed to understand of geomechanical processes underpinning permeability creation during hydraulic stimulation and related induced seismicity
Soultz	1985/1987	I	X	M	G	X	X	No water loss, circulation tests at 25 l/s.
Fjallbacka	1984/1985	I		S	E		X	Shallow wells, designed to heat greenhouses.
Hijiori	1981/1985/1987	I	X	M	G	X	X	High impedence
Yunomori	1988		X					Lack of data in the literature
Ogachi	1989/(1981)	I	X	M	E		X	High water loss
Urach	1989		X	S				Developed the concept of a single well EGS.
Altheim	1989	S			G			EGS heat pump for direct use
ASPO	1995							Äspö Hard Rock Laboratory is a research facility for future geological disposal of spent nuclear fuel.
Bouillante	1998	I			G			Thermal fracturing of a production well
Coso	2001/2002	I		S	G	X		A GTO EGS demonstration project with low pressure (<0.7 MPa) stimulation of well 34A-9.
Desert Peak	2001/2002	I/M		S	G		X	Shear-chemical-hydraulic stimulation of well 27-15
Cooper Basin	2001/2003	I		M	G	X	X	Overpressure fluid in fractures
Berlin	2001	I			G			Adjacent to an existing geothermal field
Horstberg	2003	S		S	E			Technical feasibility of the single-well GeneSys system.
Landau	2003/2004	I				X		Only stimulated the injection well.
Unterhaching	2004	S			G			Acidizing stimulation treatment
Basel	2005/(1996)	I		S	A	X		Abandonment – Large seismic events
Paralana	2005	I/S			U	X		Heat Exchanger within Insulator concept
Grob Schonebreck	2007	I/S			U	X		Sedimentary system
Insheim	2007/2008	I/S			G	X		Used a side leg injection well
Brady's Hot Springs	2009					X		Stimulation of well 15-12
The Geysers NW	1980s	S			U			Attempted stepwise injection of water to encourage thermal contraction and promote shearing of the natural fractures.
The Geysers SE	2009	S			A	X		Injection of waste water since 1997
Newberry	2009	I			U	X		Claim the injectivity increases while conducting cycling injection pressure.
Raft River	2009					X		Injection well stimulation mostly by long-term thermal injection.
Hannover	2009	S			U			Single well heat GeneSys system – salt deposition.
St. Gallen	2009	S			U			On-going
KiGam at Pohang	2010					X		Some difficulty in drilling
Mauerstetten	2011	S			U			Stimulating a limestone reservoir
Fallon FORGE	2016							A site being currently characterized as a possible full-scale EGS demonstration site.
Milford FORGE	2016							A site being currently characterized as a possible full-scale EGS demonstration site.

Notes
[a] Mostly described by Tester et.al. 2006, Breede et.al. 2013, Grant 2016, and Lu 2018.
[b] The years vary by reference and depend on interpretation of the start of the project.
[c] MIT Report; M-major, S-smaller
[d] Breede et.al.; G-Generating electricity, E-experimental w/o electricity generation, U-under development, and A-abandoned
[e] Reservoir rock type I-igneous, M- metamorphic, S-sedimentary, I/M-igneous and metamorphic, I/S- igneous and sedimentary

A possible solution may be how the reservoir was stimulated. The newest well at Rosemanowes was stimulated with viscous gel and proppants was successful in reducing water loss and the high impedance, however short circuiting became a more acute problem. At Hijori, researchers concluded that multiple wells were able to recover more of the injected water than a simple dipole system (~70% compared to ~30%).

2.4 Sustaining Thermal Reservoir Output

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 adversely impacting EGS performance. There is little practical operational experience in optimizing an EGS subsurface reservoir.

2.5 Seismic Magnitude

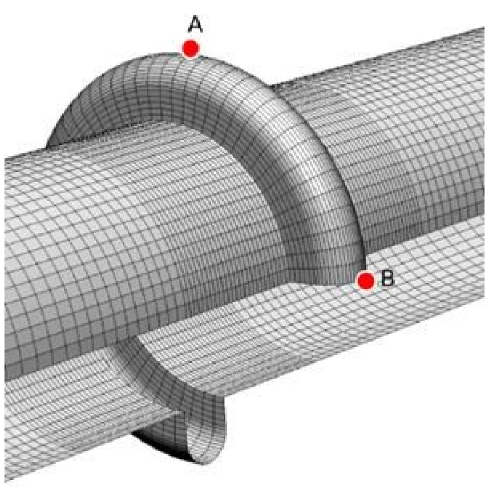
Häring (et al, 2008) summarized the Deep Heat Mining Project at Basel, Switzerland. One recommendation from this project was rather than a single massive hydraulic injection, injecting a limited fluid volume over a short time period, venting the reservoir and subsequently monitoring the resulting events. This "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.

3 TECHNOLOGIES BEING CONSIDERED FOR EXPERIMENT 3

3.1 Fracture initiation at specified locations

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 axial fractures 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 1). 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 to minimize near wellbore tortuosity and improve near wellbore flow properties to simplifying analyses. At a full-scale EGS site, the initiation of the fracture would likely be with a perforation gun or shape charges.



a)

b)

Figure 1: a) computer model of a notch within a borehole and b) a picture of a notch created by Sandia National Laboratories' borehole tool in the Experiment 1 injection well.

3.2 Use of viscous fracturing fluids

Hydraulic fracturing gels can be designed to generate viscosities ranging from 5 to over 2000 centipoises. 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 if the fracture does not experience slippage. 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.

3.3 Simultaneously stimulation of multiple wells

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.

3.4 Use of energetic fluids

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 by using an energetic system that react at rates higher than simple deflagration and lower than common high explosives (Figure 2).

Figure 2. 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.

3.5 Diverters to control short circuits

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. In 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 an 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 during stimulation and possibly during flow testing and may provide an opportunity to address circulation fluid loss in Experiment 3.

The use of fluid loss additives to control water loss during the fracturing process in both petroleum and EGS sites will likely be similar. However, controlling fluid loss to the formation during operation of the two systems will require different strategies. Fluid pressure during petroleum recovery is maintained at pressures less than the reservoir fluid pressures and therefore the fractures gain fluids rather than lose fluids. 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 (e.g. Newberry) 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.

3.6 Develop borehole zonal isolation techniques

Engineering flow control in the borehole 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 cased boreholes that are designed to 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 losses 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 one 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.

3.7 Use of multiple injector/producers wells

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 thorough model validation. The wells could also serve as monitoring wells for pressure monitoring, aperture measurements, and as ports for fluid sampling.

4 SUMMARY

The EGS Collab project can refine our understanding of rock mass response to stimulation and provide a test bed at intermediate (~10 m) scale for the validation of thermal-hydrological-mechanical-chemical modeling approaches as well as novel monitoring tools. The first two EGS Experiments 1 and 2 are planned be performed under different stress/fracture conditions, and will evaluate different stimulation processes: Experiment 1 will focus on hydrofracturing of a competent rock mass, while Experiment 2 will concentrate on hydroshearing of a rock mass that contains natural fractures.

A number of potential EGS development challenges have been identified through a literature review of past EGS field demonstrations that could be investigated as a third experiment at the Collab site. One benefit of the of Experiment 3 is that it can build of the knowledge gained from Experiments 1 and 2. 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.

Experiment 3 is scheduled to begin in 2019 will build off the lessons learned in Experiments 1 and 2 and will investigate alternate stimulation and operation methods to improve heat extraction in an EGS reservoir. This topics identified in this paper should be considered preliminary and will likely be modified as we conduct the first two experiments.

ACKNOWLEDGMENTS:

This material was based upon work supported by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE), Office of Technology Development, Geothermal Technologies Office, under Award Number DE-AC07-05ID14517 with Idaho National Laboratory. The United States Government retains, and the publisher, by accepting the article for publication, acknowledges that the United States Government retains a non-exclusive, paid-up, irrevocable, world-wide license to publish or reproduce the published form of this manuscript, or allow others to do so, for United States Government purposes.

REFERENCES

Breede, K., Dzebisahvili, K., Liu, X., and Falcone, G., A Systematic Review of Enhanced (or Engineered) Geothermal Systems; Past, Present and Future. *Geothermal Energy*, **1:4**, (2013).

Cappetti, G., Parisi, L., Ridolfi, A., and Stefani, G., Fifteen Years of Reinjection in the Larderello-Valle Secolo Area: Analysis of the Productivity Data, World Geothermal Congress, **1997:2000,** (1995)

DOE, An Evaluation of Enhanced Geothermal Systems Technology, U.S. Department of Energy Report, (2008) online: https://www1.eere.energy.gov/geothermal/pdfs/evaluation_egs_tech_2008.pdf

Grant, M.A., Physical Performance Indicators for HDR/EGS Projects, *Geothermics*, 63, **2:4,** (2016).

Häring, M.O., Schanz, U., Ladner, F., Dyer B.C.: Characterization of the Basel 1 enhanced geothermal system. *Geothermics*, (2008), doi:10.1016/j.geothermics.2008.06.002.

Hawkins, A. J., D. B. Fox, M. W. Becker, and J. W. Tester, Measurement and simulation of heat exchange in fractured bedrock using inert and thermally degrading tracers, *Water Resour. Res*., 53, **1210:1230**, (2017)

Kelkar, S., WoldeGabriel, G. and Rehfeldt, K., Lessons learned from the pioneering hot dry rock project at Fenton Hill, USA, *Geothermics*, 63, **5:14**, (2016)

Lu, S., A Global Review of Enhanced Geothermal Systems (EGS), *Renewable and Sustainable Energy Reviews*, in press, (2018).

Olasolo, P., Juarez, M.C., Morales, M.P., Ameco, S.D. and Liaret, I.A., Enhanced Geothermal Systems (EGS): A Review, *Renewable and Sustainable Energy Reviews*, 56, **133:144**, (2016).

Smith, M.E. and C.T. Montgomery, Hydraulic Fracturing, CRC Press, Taylor and Francis Group, (2015).

Stober, I., Depth- and pressure-dependent permeability in the upper continental crust: data from the Urach 3 geothermal borehole, southwest Germany, *Hydrogeology Journal*, 19, **685:699**, (2011)

Tenzer, H., Development of Hot Dry Rock Technology, *GHC Bulletin*, December, **14:22**, (2001)

Tester, J., Anderson, B., Batchelor, A., Blackwell, D., DiPippo, R., Drake, E., Garnish, J.,Livesay, B., Moore, M., Nichols, K., The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century. MIT. (2006).

Ziagos, J., Phillips, B.R., Boyd, L., Jelacic, A., Stillman, G., and Hass, E., A technology roadmap for strategic development of Enhanced Geothermal Systems, Proceedings, 38^{th} Workshop on Geothermal Reservoir Engineering, Stanford University, SGP-TR-198, (2013).