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**Toward More Efficient Heat Mining: A Planned Enhanced Geothermal System Demonstration Project**

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EGS, Engineered Geothermal Systems, stimulation, hydroshearing, The Geysers, induced seismicity

**ABSTRACT**

AltaRock, in partnership with NCPA, has been working on a project to demonstrate new technology aimed at lowering the cost of an Engineered Geothermal System (EGS). The stimulation target is a hot, intrusive body in Northern California underlying an existing geothermal resource. An EGS creates or enhances a geothermal reservoir by shifting critically stressed fractures in hot rock through hydroshearing, and then cycles water through the fractures to mine the in-place heat. The goal of the project is to create multiple independent fracture zones from a single well in order to increase the aggregate flow rate without increasing the pressure drop through the system. Because well drilling and completion together represent the biggest single cost of an EGS, the ability to increase flow rates without resorting to additional wells would significantly reduce the cost of this power-generation technology. A microseismic array has been installed to monitor the fracturing progress and post-stimulation development in near real-time. New methods have been lab tested and modeled numerically to evaluate reservoir heat-exchange area, flow-paths, and fracture connectivity. These will be deployed in the field during flow back testing of the stimulated zones. Fluid chemistry will be monitored for chemical changes.

**Introduction**

A recent assessment by the USGS (2008) concluded that 510,000 MWe of Engineered Geothermal System (EGS) resource exists in the western continental United States alone. The MIT (2006) study found that 100,000 MWe will be economic by 2050; making this goal a reality requires that we make the effort to improve EGS economics, starting today.

We performed a sensitivity study on the cost of power from EGS by varying each cost component from -40% to 40% improvement (Figure 1). EGS power cost is most sensitive to flow rate per production wells (yellow diamonds in Figure 1). The possibility of improving flow rate much beyond 40%, and in fact by as much as 300%, exists given only incremental technology improvements. The maximum potential improvement for drilling cost we expect would be only 20% with incremental technology improvement. Therefore, to improve the economics of EGS, methods must be developed to improve flow rate per well without decreasing the life of the reservoir by allowing too rapid a passage of water through the created fractures.

AltaRock Energy received a DOE award in the fall of 2008 to demonstrate methods for EGS reservoir development through...
multiple-zone stimulation. This will be done by (a) using innovative mechanical and non-mechanical methods to create multiple fracture zones; (b) map fluid pathways using microseismic and other methods during stimulation; then (c) validate that pathways have been created using tracer testing and modeling.

The demonstration project is located on the NCPA leases from the BLM in the southeast portion of The Geysers geothermal field (GGF) in Northern California. The field has been under commercial development since 1960, producing steam from a vapor-dominated reservoir. More than 600 deep geothermal wells have been drilled in the GGF. The lateral extent of the wells is outlined in Figure 2. The locations of more than 20 power plants are also shown, including the two NCPA 110-MW power plants located at the southeast end of the field. The existing NCPA power plants operate at much less than full capacity. NCPA would like to bring them to capacity using EGS-generated steam.

As shown in Figure 3, GGF production peaked in 1987. Although two injection pipelines have slowed or halted the decline, increasing production further is not likely possible with the current water supply and injection scheme. It is possible that EGS will more efficiently use the injected water. Thus in additional to the proprietary EGS development techniques that will accrue to AltaRock, the demonstration project will also show the commercial viability of separate EGS development beneath the GGF production zone. We will develop test data to show that a separate EGS reservoir has been created through stimulation beneath NCPA’s normal Geysers reservoir and energy produced by the project can be made available to NCPA for use in its projects.

In brief, the project plan is to deepen the existing NCPA well E-7 to a total depth (TD) of around 3,660 m. The goal is to stimulate or hydroshear at least 3 different zones to maximize the eventual flow rate. Once stimulation is completed, the drilling rig will be skidded by about 15 m, and a new well, E-8, drilled to intersect the zones created at E-7.

Hydroshearing

The demonstration project goal is to create a permeable reservoir through hydroshearing of existing fractures. We use the term hydroshearing to indicate that the goal is to cause existing fractures to dilate and slip in shear (Figure 4). Shear-slip will radiate seismic energy that can be used to map the fracture location and size.

Hydroshearing is preferable to tensional fracturing because (a) it takes less fluid pressure to cause a permeability enhancement; (b) shear along irregular surfaces (as most fractures are) will prop and maintain open fractures even when fluid pressure is reduced;
and (c) tensional fracturing would grow upwards, raising the risk of connecting the EGS reservoir to the existing steam reservoir. Increasing fluid pressure downhole will reduce normal stress on critically oriented pre-existing faults and fractures. The direction and magnitude of the least principle stress are currently not known, and will be determined by a mini-frac test and borehole televiewer run just below the casing at a depth of approximately 2900 m.

**Demonstration Project Plan**

The demonstration project at NCPA Geysers has been divided into three phases. As of this writing (June 2009) Phase I–resource characterization–is complete. Phase II–work over well and hydroshearing, has begun and will continue into the early fall of 2009. Phase III–circulation testing and long term monitoring–will last for a year after Phase II is complete. Activities of the three phases are detailed below.

**Phase I**

Prior to drilling and stimulation, approval and agreements from the landowner, BLM, and the lessee, NCPA, as well as permits from the state of California and Lake County, were necessary. One important requirement was that AltaRock assess the risk of induced seismicity (IS) likely to be caused by the project activities and the impact on the local community of Anderson Springs. This is a sensitive issue because with increased injection in the GGF, seismicity has increased to a level of over 1,000 seismic events with M>1.5 (Figure 3). We concluded that although the local residents currently endure a high level of felt events—a mean occurrence interval of Modified Mercalli Intensity (MMI) of > IV of 13 days—the EGS project would not significantly increase that level of felt events. The results of the report, which were accepted by the regulators, are further described later in this paper.

Another important task that needed to be completed before drilling and stimulation was the design and installation of a microseismic array (MSA), which is critical to monitor fracture growth location and size during and after hydroshearing. The MSA is arranged in two rings at 1 and 3 km away from the stimulation well E-7 (Figure 5). Seismometers were installed at depths below the surface of 105-155 m in order to reduce noise and thus improve sensitivity. A 3-D velocity model will be created specific to the MSA, using the 2-3 months of background seismicity currently being collected and a calibration shot fired at the bottom of E-7 once TD has been reached.

**Figure 5.** An 8-station microseismic array has been installed in 1 and 3 km rings around the injection well. Seismometers were installed at depths of 350-500 ft deep in order to reduce noise and improve network sensitivity.
In order to properly specify the stimulation target and the borehole inclination and azimuth at that depth, study of the regional and local stress regime under E-7 was undertaken in Phase I. A summary of the analysis of microseismicity, fracture and fault maps for stress orientations is provided later in this paper. The conclusion of the study is that the orientation of the principle stresses at 3,050 m depth below E-7 is ambiguous, making the results of the mini-frac and borehole televiwer run critical to fine-tuning the stimulation design.

Finally, Phase I has included detailed planning of the scope, schedule and budget for drilling and stimulating the two wells. Single well and circulation tests have been designed to quantify the flow rates and heat transfer capacity of the EGS reservoir. Specialized cements, diverter compounds, tracers, and sampling equipment are being manufactured and tested for use in the project.

Phase II

Phase II started in June 2009. Figure 6 shows a geologic cross section of the site, along well locations and depths, both existing and planned. The E-7 well has been sidetracked at ~975 m and drilling has begun through a ~1525 m thickness of greywacke, mélange, and greenstone of the Franciscan Formation which hosts the normal Geysers steam reservoir and then ~460 m into the underlying felsite. Casing will be set to ~2,900 m TVD, using special high temperature, foamed cements and the reverse-cementing technique.

Below the casing, a mini-frac will be performed in a short section of open hole to determine the magnitude of the least principle stress. Then, in a longer section of open hole, a high-temperature, ultrasonic borehole televiwer (BHTV) will be run. Analysis of the BHTV images will allow determination of the principle horizontal stress directions, fracture orientations and fracture intensities.

The well will then be deepened to ~3,810 m, providing up to 610 m of potential EGS reservoir. In order to maximize the potential to intersect existing fractures likely to slip in hydroshear, E-7 will be directionally drilled at ~30º deviation to the north or northeast. Once the open hole is drilled it will be prepared and instrumented for stimulation. To divide the resulting open hole into an upper and lower zone, a scab liner with PBR (polished borehole receptacle) will be set. Fiber optic cable will be installed to continuously monitor temperature and pressure.

Hydroshearing will commence by pressurizing the open hole below the scab-liner and PBR by filling the well with water. Although it is possible that just 1,525 m of hydrostatic head in the borehole will be sufficient to cause hydroshearing, we will be prepared to apply 13.8 MPa of wellhead pressure. We anticipate that 7 days of injection per stimulation zone will be sufficient to create a reservoir with a 460-m horizontal half-length. The second and third stimulation zones will be stimulated using AltaRock’s proprietary diversion methods. Once three EGS reservoirs have been created in E-7 the no-go plug will be removed and single well test performed in all three zones simultaneously.

Phase III

Once Phase II achieves the planned objectives, the decision to proceed with Phase III, drilling of the production E-8 will be made. E-8 will be drilled into the hydrosheared zone, which will be located using the MSA. Our production goal of 25-35 kg/s of steam per fracture with up to four fractures in the production well should be sufficient for 10 MWe.

An important part of EGS-based energy is understanding the chemical reactions that occur in the stimulated fracture network. Chemical tracers, both thermally reactive and conservative compounds, can be used to infer reservoir properties such as heat exchange surface area, residence time and the amount of native brine present in the rock prior to stimulation (Sanjuan et al., 2006). The evolution of other chemical species, including major ions, trace metals and non-condensable gasses (NCG), can help constrain reservoir properties such as rock composition and water/rock ratios (Xu et al., 2009). Furthermore, understanding the nature and extent of water/rock reactions can help predict and plan for scale problems and changes in porosity that may dictate how a geothermal resource is managed on a day-to-day basis.

During the circulation testing and long-term monitoring phase of the project, we will be collecting extensive time series chemical data throughout the post-stimulation flow-back tests and also during longer term flow tests. In the early stages, samples will be collected at 1-hour intervals and analyzed for conservative and thermally reactive tracer concentrations. This data will be used to determine surface area, residence time and percentage of native brine in the produced fluid. Samples will also be collected at 8-hour intervals and analyzed for major anions and cations, trace metals and NCG. This latter data set will be used to conduct history

Figure 6. Cross section of proposed project site with deepened existing well. The EGS resource is about 300 m below the top of the felsite, and the EGS wellbore TD will be at about 3,500 m depth.
matching with numerical models of the reservoir to help constrain model parameters. Combined with the information acquired from tracer chemistry, we will be able to paint a more complete picture of the pressure, temperature and spatial configuration of the subsurface circulation pathways. The monitoring results will inform operational changes in the EGS reservoir to maximize production and lifetime.

**Stress Model**

The primary selection criteria for identifying EGS drilling targets at most sites will be, in order of importance, (1) temperatures greater than 200-250°C at 1-5 km depth; (2) rock type at the depth of interest; and (3) stress regime. At GGF, the first two criteria are well known— at the target depth of 2,900-3,810 m, the temperature will be 245-285°C and the rock type will be the “Felsite” silicic granite pluton that underlies much of The Geysers. That leaves the stress regime as the primary unknown. The Geysers region is located in the Coast Ranges of Northern California, which is within a broad zone of tectonic deformation associated with the boundary between Pacific and North American Plates. The primary structure of this boundary area is the San Andreas Fault (SAF). The secondary faults within the deformation zone—which are sub-parallel to the SAF and have the same right-lateral strike-slip sense of movement—create a complex stress regime. Overall, the SAF system will produce a strike-slip faulting regime with a horizontal extensional direction of 105° and a horizontal compressional direction of ~15°. However, this simple regime is complicated when a secondary fault system bends or steps eastward, causing a local switch to a normal faulting regime, or when the bend is westward, causing a local switch to a reverse faulting regime. The local Quaternary faults near the SE Geysers are the Collayami Fault and the Mercuryville Fault. However, it may be that an ancient crustal weakness, the Big Sulphur Creek fault zone (BSCFZ), which bounds the steam reservoir in this part of the GGF (Moore and Gunderson, 1995), plays a more important role in the local stress regime.

Over 1,000 microseismic events with magnitudes ranging from 1.5 to 4.0 occur annually in The Geysers (Stark et al., 2005; Figure 3) due to thermal contraction and porosity changes from injection of cool water (Mossop and Segal, 1999; Rutqvist and Oldenburg, 2004). Of these, focal mechanisms have been derived for about 400 of the larger events. altcom (2009) performed stress inversion of the focal mechanisms by dividing the events into geographic groupings. This analysis indicates that the tectonic extension direction of ~105° does control the fault-slip in all areas except near the BSCFZ where the extension direction is perpendicular to that zone (15°). However, even where the tectonic extension direction controls, a strong overprint caused by reservoir production and injection activities causes much local variation. Most of the seismic events that indicate a variable stress field occurred above the felsite, in the steam reservoir. We assume that at depth in the felsite, the overprint will be minimized and that the tectonic stress regime (strike-slip faulting with minimum principle stress direction of ~105°) will predominate. In that case, the faults and fractures best oriented for shear will be sub-parallel to the structural grain defined by the pre-existing NW-SE trending strike-slip faults.

**Induced Seismicity (IS)**

When the total volume of water injected in the NCPA lease roughly doubled in 1998, the rate of microseismic events also doubled. However, it is difficult to directly relate the observed microseismicity in the NCPA area to any specific single NCPA injection well, due to the relatively low injection rates, even though there are up to a dozen or so relatively closely spaced NCPA injection wells that are continuously active at any one time.

The largest seismic events of the past 12 years in the NCPA area occurred within the Big Sulphur Creek Fault Zone, a fault that is not considered active at the surface but does form the southwestern boundary of the steam reservoir. Because the BSCFZ is outside of the areas of water injection and steam production, the BSCFZ seismic events are considered to be tectonic, and unrelated to past injection activities. Nevertheless, the EGS Demo Project activities have been designed to avoid this zone and the uncertain engineering conditions that it might present.

The EGS Demo Project will involve four very different intervals of IS: (1) background microseismicity, (2) microseismicity due to the creation of the engineered reservoir, (3) microseismicity, if any, related to ~2 years of circulation testing (referred to as long-term data collection and monitoring), and (4) microseismicity, if any, during operation of the geothermal resource for power generation. While past history at the GGF may help predict microseismicity in the third and fourth intervals, predicting microseismicity in the second interval, stemming from engineered reservoir creation, required review of past EGS experience and application of geomechanical models with inputs specific to this EGS Demo Project. Worldwide EGS-project IS data indicate that the largest IS event linked to EGS activities was a M=3.7 event in the Cooper Basin of Australia.

The best analog for the EGS Demo Project, based on rock type (both are granitic), stress regime (transitional normal faulting to strike-slip), injection rates (57-68 kg/s), and length of injection (1-2 weeks), is the Soutlz-sous-Forêts, France, EGS project where the maximum IS event had a magnitude of 2.9. These results are confirmed by applying three different geomechanical models for the specific engineering parameters of the EGS Demo Project at the NCPA site (Greensfelder et al., 2008). Those models indicate that the maximum possible realistic IS related to the EGS Demo Project will most likely be less than M~2.3.

**Impact on the Local Community**

About 2 miles northeast of the EGS demonstration project is Anderson Springs, the former location of a hot mineral springs and resort developed in 1876 (Anderson Springs Community Alliance, 2007). The resort and hot springs no longer exist, but there are many homes occupied both year-round and seasonally in a narrow valley along a small creek. In 2004, when injection volumes in the SE Geysers were increased, a strong-motion seismic station, ADSP, was installed by Calpine in the community to document the effects of induced seismicity on the residents. A Calpine power plant and wells are about 0.5 mile from the upstream end of Anderson Springs.

Since 2004, ADSP has recorded nearly 500 events with peak horizontal acceleration (PHA) greater than 1.4% g (MMI equivalent
> IV) including four events with PHA>18% or MMI equivalent of VII. A MMI of IV is a seismic event felt by many people indoors but unlikely to cause damage, while a MMI of VII is felt by all and may damage poorly built structures (Wood and Neumann, 1931). What is surprising is the relatively high PHAs (3.9%-9.2% g, MMI equivalent of V) recorded at ADSP for small (M<2.5) events. Figure 7 shows the epicentral distance and magnitudes of the PHA>3.9% g events. Most (66%) of these events were closer than 2 miles. The events farther than 2 miles all had magnitudes greater than 2.5. These two numbers are important, because the AltaRock hydroshearing demonstration will be occurring at about 2 miles with no events predicted above M=2.5. Therefore, based on past history, an event with M<2.5 at a distance of >2 miles away, would cause an intensity MMI IV or less.

**Figure 7.** Locations of seismic events generating peak horizontal acceleration greater than 3.9% g at ADSP (MMI equivalent > IV) all GGF.

### Conclusion

The goal of AltaRock’s EGS demonstration project in the NCPA portion of The Geysers is to hydroshear multiple zones to maximize the flow rate between the injector and producer, and thus demonstrate and develop innovative techniques that will improve the economics of EGS. As of this writing (June 2009) Phase I, resource characterization, is complete. Drilling to the stimulation target of Phase II, has begun and should be near completion when we meet for the annual GRC conference.

### References


