Temporary Diverters for EGS Reservoir Optimization—Field Applications

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EGS, Reservoir, diverter, injection well, temporary, degradable, slotted liner, stimulation

ABSTRACT

Achieving multiple zone stimulation in an open-hole section of an EGS well could significantly reduce the cost of EGS power production by increasing flow capacity and production on a per-well basis. To prove this concept, a first operational step was taken in a geothermal field. The goal of the operation was to test the use of AltaRock Energy Inc. (AltaRock) proprietary diverters system[1] in temporarily sealing off fractures in a geothermal reservoir and optimizing the injection/production profile of the given well. Success of the operation serves as a basis for multiple zone stimulation in EGS and conventional geothermal reservoirs. Multiple zone stimulation allows for greater production and substantial reduction in the cost of EGS power generation. GETEM modeling results for EGS show a reduction in the cost of power of up to 50 percent if three fracture zones can be successfully stimulated, versus the current method of single fracture set stimulation.

Temporary diverters block flow to zones that are already stimulated or where stimulation is not desired. These proprietary diverter materials decay due to thermal degradation, producing environmentally benign decomposition products. Successful field results are presented along with a detailed explanation of the benefits of temporary diverters and how they could positively impact EGS projects and geothermal power production in general. These methods will be further validated at the upcoming Newberry Volcano EGS Demonstration. This work has been funded in part by DOE Grant DE-EE0002795, "*Temporary Bridging Agents for Use in Drilling and Completion of Engineered Geothermal Systems*."

Introduction and Background

Increasing the production of conventional geothermal wells will provide significant benefits to operators. Stimulation of geothermal wells using large volumes of water has been successfully accomplished in the past and resulted in the improvement of the formation permeability and flow in wells. For EGS systems, flow capacity has typically been limited only to the fractures created by pumping water from the surface through a limited number of exit points in the open-hole reservoir rock.

One way to improve the effectiveness of a hydrothermal well stimulation treatment would be to temporarily, hydraulically isolate the stimulated fractures in order to create and/or stimulate additional fractures. This can improve the overall connectivity of the well to the thermal production source by increasing permeability and the number of fractures connected to the well. Similarly, it may be possible to improve production on a per-well basis in an EGS well by creating multiple fractures by first stimulating one set of fractures (Figure 1) and then temporarily isolating those fractures while a second set of fractures is stimulated. One could attempt to do this with the use of a mechanical isolation tool such as an open-hole packer (Figure 2), but this would require a drilling rig during the stimulation treatments resulting in additional costs and increased operational risk of packer failure (i.e. getting the packer stuck in the hole, etc.).

A novel tool to improve the process of multiple zone stimulation without the use of packers is proprietary temporary diverters developed by AltaRock. These diverter compounds would allow

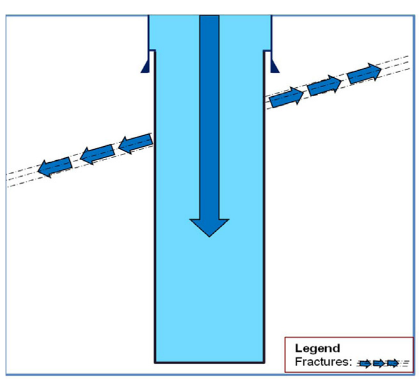

Figure 1. EGS Well with Single Fracture Network.

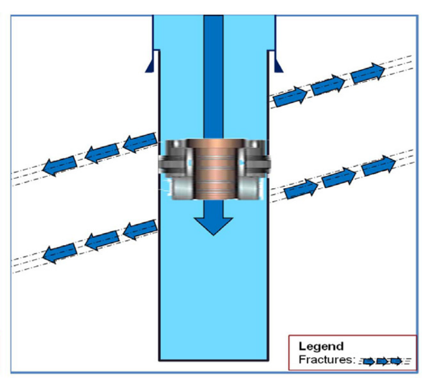

Figure 2. Multiple Fracture Creation with Open-Hole Packer.

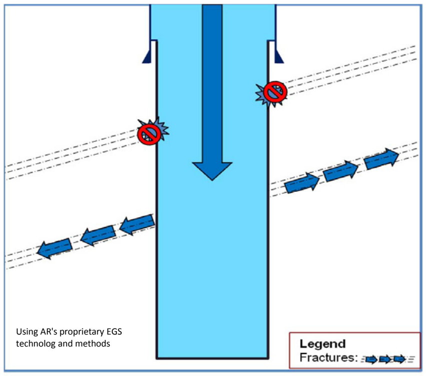

Figure 3. Creation of Multiple Fractures with Diverters.

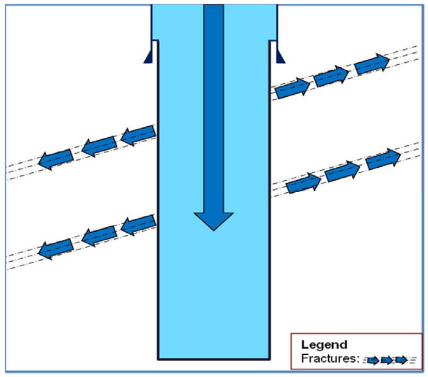

Figure 4. EGS Well with Multiple Fracture Networks.

the temporary sealing of existing or newly stimulated fractures so that additional fractures could be stimulated (Figures 3 and 4). This can be accomplished by first stimulating a set of fractures by pumping water from the surface into the well. After the first set of fractures is stimulated, a diverter material is pumped into the well, sealing off the fractures. As additional pressure is applied to the well, a second set of fractures will be opened and stimulated. At the end of the treatment, injection of cold water is stopped, heating the well back up to its original geostatic temperature. This causes the diverter materials to degrade and dissolve, leaving all the stimulated fractures open for circulation and flow during the operation of the EGS field.

A significant advantage of using a chemical diverter system over other mechanical systems for creating multiple stimulated fracture networks is the elimination of the need for a drilling rig during the stimulation. In addition, two, three, or more stimulated fractures can be created in succession using a temporary diverter system simply by repeating the process described above. The more fractures created, the greater the productivity of the wells, and ultimately, the lower the cost will be to generate electricity.

The same method of using chemical diverters can be used in the stimulation of conventional, low permeability hydrothermal wells. The current producing fractures are first stimulated (if desired) then a temporary diverter is pumped in to seal off the existing fractures. Afterwards additional fractures would be stimulated to improve production from the well.

Temporary Diverters – Design, Application and Benefits

A number of possible temperature sensitive, temporary diversion systems were considered for the field test. The optimal system for this application consisted of a proprietary material which was specifically designed to pass through slots in the liner and bridge off the fracture face. The proprietary chemical diverter material was pumped into the well intermittently during the injection testing.

For normally stressed rock stimulated by the pumping of water from the surface, one would expect that the first group of generated fractures would open near the top of the open-hole interval, and subsequent fractures to be stimulated will occur below the previously stimulated fracture network. This allows the advantage of continuous cooling of the diverters which seal the existing fractures above the zone currently being stimulated. Keeping the diverters cool slows down the degradation process, sealing the fractures for a longer period of time.

The chosen diverter material would remain intact during the stimulation treatment, which was expected to be below 200 °F due to the cooling effect of the injection water. After the stimulation, the material would then thermally degrade and dissolve into the wellbore fluid. The degradation was accelerated by the increase in wellbore temperature that occurred after the injection of cold water was terminated and the well re-equilibrated to its pre-cooling condition. The expected degradation time, based on laboratory tests, was within days after the stimulation.

There are several advantages to using a temporary diverter system over a mechanical system. The diverter material can be pumped into the well to create a seal without a drilling rig on site. Because this is a self-degrading system, a rig is likewise not needed to spot special chemicals into the well (to help remove the temporary diverter), or similarly, if an acidic soluble system is employed.

Eliminating the use of a drilling rig not only eliminates associated operational risks, but it also means significant potential savings for other stimulation applications. Drilling rig mobilization costs and day rates can be very high. The typical stimulation treatment for an EGS or hydrothermal well usually takes several days.

Multiple stimulated fracture systems can theoretically be created in rapid succession without having to stop the stimulation process. This eliminates the process of having to move the drill pipe in and out and re-set a packer. Should something go wrong during testing, pumping can easily be stopped, and the diverters will dissolve in the wellbore. On the other hand, an open-hole packer can get stuck, incorrectly set, or cause other operational problems, possibly requiring re-drilling of an entire open-hole section.

Cost Analysis Using GETEM

The GETEM (Geothermal Electricity Technology Evaluation Model) was used to compare cost of power production for wellbores containing one versus three stimulated zones. Table 1 presents a summary of the cost of production for various power plant types and fluid input temperature. Analysis results demon-

Table 1. GETEM Cost Analysis for Flash and Binary Production with Single and Three Fractures.

Flash/ Binary	Temperature (°C)	Improvement	Cost of Power2010 (cent/kw)
Flash	250	N/A	11.53
Flash	250	3x flow rate	6.88 (40% less than the case above)
Binary	175	N/A	31.94
Binary	175	3x flow rate	16.02 (50% less than the case above)

*Note: Assumed 30 kg/sec base flow rate and 4 km well depth.

strate a significant drop in the overall cost of power when three stimulated zones are present. A 40% decrease in power production was achieved through the Flash System @ 250 °C and a 50% reduction in cost was achieved through the Binary system @ 175 °C.

Field Demonstrations

Injector Test

AltaRock first conducted a diversion system test in a well with an un-cemented, slotted liner. The objective of the test was to demonstrate the effectiveness of a diverter material in temporarily sealing existing geologic fractures. The test well exhibited two low pressure steam entries at shallow depth above the slots. While fractures were encountered at depth closer to total depth (TD), they were not highly permeable. The test well was not a commercial producer. The specific goals of the first diverter test were to:

- Prove the effectiveness of thermally-decomposing diverters in blocking permeable fractures currently taking fluid;
- Temporarily modify the injection profile by forcing fluid into deeper fractures;
- Test the effectiveness of diverters in a slotted liner with ¼ inch slots
- Test the effectiveness of diverters in a highly permeable, naturally-fractured rock.

Prior to the diverter testing, a Pressure Temperature Spinner (PTS) survey was conducted to obtain the well's pre-test injectivity and conditions. An injectivity of 1.7 gpm/psi was calculated. The rate from the first injectivity test was not held constant because water was delivered directly from the power plant. Following this injectivity test, the well was shut off. A temperature buildup and pressure falloff test was conducted to calculate pre-testing reservoir properties. To compare results, a similar step rate injection test and pressure falloff test was conducted two weeks after the initial diverter test. To estimate the initial temperature and pressure at total depth, Horner analyses were performed from the test data on the pressure-falloff and temperature buildup. (Horne, 1995).

After the initial injectivity test, the diverters were injected with water at 500 gpm with a PTS tool sitting at monitored depth. Injection continued until a pressure increase was observed and the isothermal zone extended deeper into the well. After the first diverter pill had been pumped, the slotted interval was logged. Then, with the PTS tool parked at monitoring depth, a second diverter pill was injected at a rate of 500 gpm until similar results were observed.

Figure 5 illustrates pressure and temperature behavior versus time as the diverter was pumped while the tool was held stationary at the monitored depth. The injection rate throughout the pumping of diverters was held constant at 500 gpm. Note the extent of the temperature drop (red) and pressure rise (blue) caused by the diverters. After the first diverter pill was pumped, temperature dropped 28°F and pressure increased 182 psi in thirty minutes. After the second diverter pill was pumped, temperature dropped an additional 7°F and pressure increased an additional 80 psi. This drop in temperature and increase in pressure indicate that cold water is being injected past the tool string at the currently monitored depth. The temperature after the second diversion leveled off after 25 minutes and started to increase gradually. The gradual increase was most likely the result of improvement in zonal permeability due to fracture extension at the higher pressures. This permeability enhancement is shown by the post-test temperature survey in Figure 6, which indicates a much larger amount of fluid exiting the well 230 feet below the deepest injection interval previously visualized. The total drop of temperature for this diverter test was 35°F and pressure increase was 262 psi. Hydroshearing of additional natural fractures may have occurred as indicated by the slow decline in pressure as the test progressed.

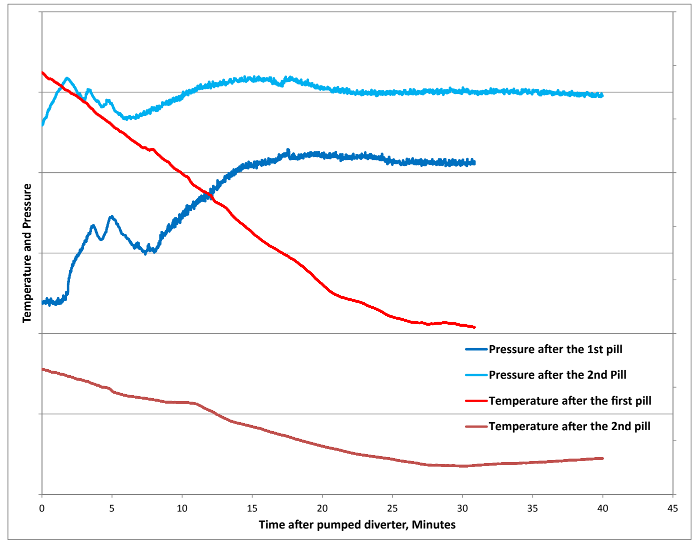

Figure 5. Pressure and temperature versus diverter pumping time during the field injection test.

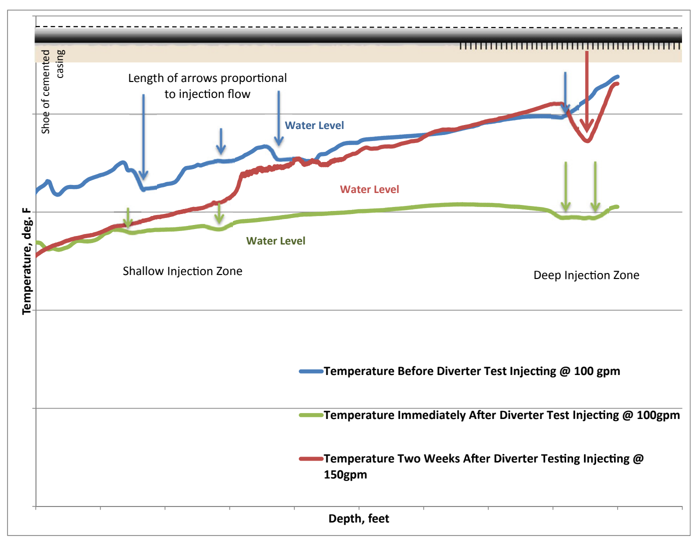

Figure 6. Temperature versus depth showing the change in well profile pre and post-test.

Figure 6 illustrates temperature versus depth at various times as the PTS tool was lowered into the wellbore to the monitored depth while injecting. The pre-diverter test temperature (blue) indicates original injection points at four different injection zones. It appears that highly depleted steam zones were pulling water above the slotted liner behind the blank pipe. It can be inferred that this phenomenon caused slug flow in the annulus above the fluid level, causing the temperature to cool above the slots. We expect this behavior to be transient. After the first diverter pill, the top of the slots logged indicated that additional injection was deeper than originally observed injection zones. After the second pill of diverter injection, the temperature survey (green) showed that the shallow depth injection zones were successfully plugged, indicating little to no injection. The injectate was pushed deeper, forming an isothermal zone. The temperature survey a day after the diverter testing demonstrated minimal shallow injection and a very large injection zone within the deep injection zone. Two weeks after diversion, the log run showed no flow exiting at the upper zones. This is likely the result of the deeper water level depth (red). This injection profile is not as large as the one exhibited right after diverter testing in (green). One possibility for this is that since the diverters dissipated, the fractures created from the diverters also closed up.

The pressure versus depth while injecting, as indicated **(**Figure 7**)** throughout the test by the PTS tool is also a good indication of diversion. The original fluid level detected is shown by the change in the pressure profile (blue). Pressure increased after the first pill of diverter was pumped (shown in red). The injection rate increased from 100 gpm to 500 gpm. After the diverter test, the injection rate returned to 100 gpm. The water level after the first diverter pill was projected to be higher, and the post-diverter testing survey result (purple) indicated an almost 200 feet increase in water level. This increase in water level indicates a successful diversion, but also indicates that the diverter remained in the fractures to some extent.

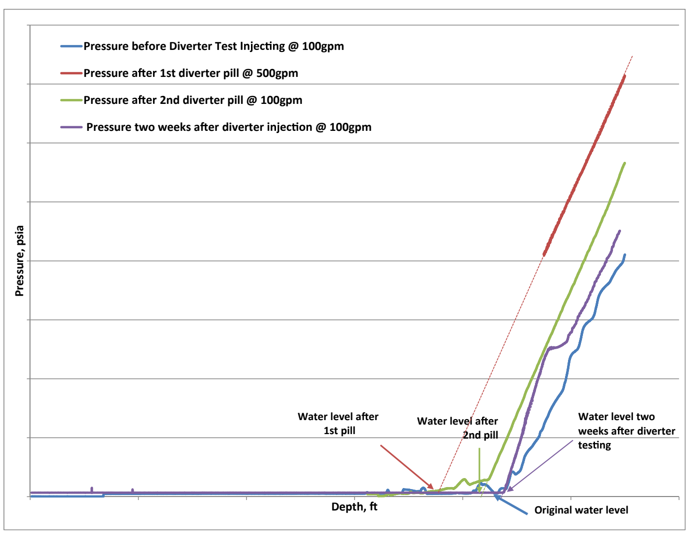

Figure 7. Pressure vs. Depth.

A second injectivity test was performed one day after diversion to test the degradation of diverters. An injectivity of 0.75 gpm/psi was calculated. We believe this injectivity is lower than the pre-diverter test injectivity because the diverters remained in place as they needed a few more days to completely degrade. This diverter material is designed to degrade to lactic acid with passage of time and exposure to temperature. Conceptually, as the well heats back up under normal injecting conditions, all of the original fractures should be re-opened. In order to assess the degradation of the existing diverter material and the modified injection profile, a third PTS logging run, along with step-rate injectivity testing and pressure fall off/temperature build up, was conducted two weeks after initial diverter testing. An injectivity of 0.85 gpm/psi was calculated. This injectivity is higher than the post-diverter test injectivity, indicating that the diverters had completely degraded. This injectivity indication however is lower than the pre-diversion test because injection at upper steam zones seemed to cease.

Producer Stimulation

After the first successful diversion test, a second well from the same field was selected to be stimulated using AltaRock's proprietary diverter technology. Diverters were used to temporary seal off existing permeable zones in the producer after each stage of stimulation in order to create multiple flow paths and improve productivity of the well. The following methods were used to assess the success of this stimulation:

- A tracer test using reactive and non-reactive, vapor-phase tracers was conducted to determine the swept area before and after stimulation for comparison purposes. Trace return concentration was also used to illuminate any connections to surrounding wells.
- Steam production flow rate was measured before and after stimulation with a testing muffler and orifice in order to quantify the stimulation success in terms of steam flow and power generation.
- A flowing temperature and pressure survey was run to compare the steam production profile before and after stimulation. Diverter stimulation should create additional production zones and enhance existing steam production intervals.
- Microseismic monitoring was used to map any microseismic events that occurred during the stimulation. Micro-seismicity could be an indication of successful stimulation of pre-existing fractures and could provide information about the size and extend of the stimulated volume.

Alcohol vapor phase tracers (2-propanol) combined with liquid tracer were injected into the well prior to diverter stimulation. Three wells closest in proximity were sampled for tracer returns. After the last stage of diverter stimulation, a second pair of vapor phase tracers (1-propanol) combined with liquid tracer was injected. Preliminary analyses showed rapid returns of 2-POH tracers in two of the sampled wells (Figures 8 and 9) within a few hours of injection. However, no tracer returns were captured immediately after the injection of the 1-POH tracers during diverter stimulation. This tracer result is a good indication that the flow path between the stimulated well and Producers 1 and 2 was temporarily blocked by diverters. At the end of diverter stimulation, injection was shut off to allow the well to heat back to static temperatures. The next few tracer samples taken after the stimulation phase showed varying amount of tracer concentration in all three producing wells. Not only do these phenomena indicate that the diverter material has degraded, leaving the connection between the wells open once again, but a new connection was created between Producer 3 and the stimulated well (Figure 10).

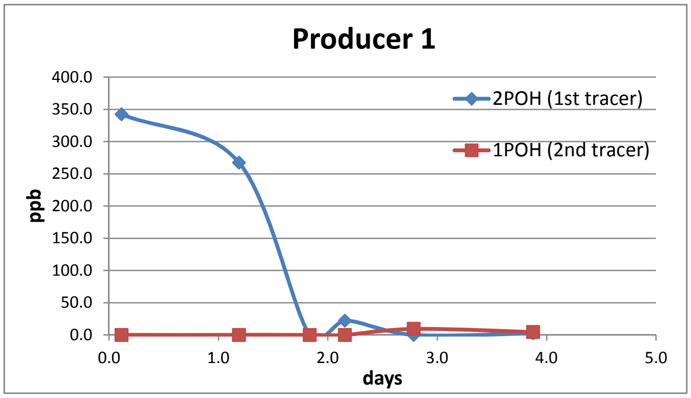

Figure 8. Tracer Response Producer 1.

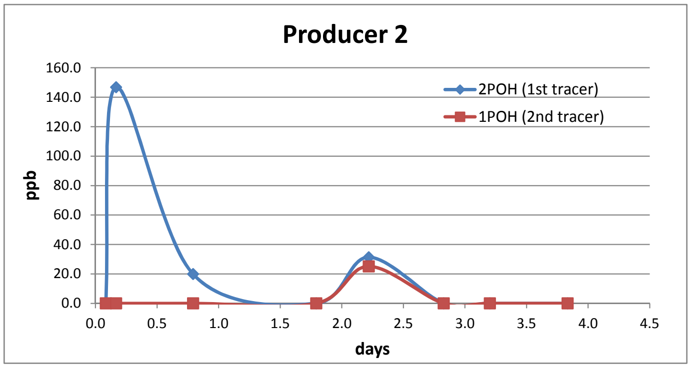

Figure 9. Tracer Response Producer 2.

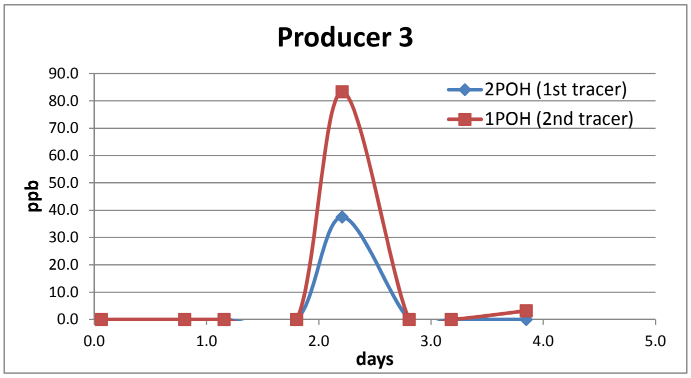

Figure 10. Tracer Response Producer 3.

After stimulation, the wellhead pressure returned to initial shut-in conditions with-in 24 hours. A post-stimulation productivity flow test was then conducted at three different wellhead pressures using a 4 inch orifice plate and testing muffler. Similar testing was conducted prior to stimulation, and the flow rates showed a 100% improvement. The productivity curve comparison shown in Figure 11 also indicates higher production flow rates at the same wellhead pressure post-stimulation.

The wellhead pressure build-up data from the two flow tests was used to conduct a Horner analysis in order to estimate the transmissivity before and after stimulation. Using an equation from (Upton et. al.1986), the transmissivity of the well prior to stimulation was calculated to be 34,758 md-ft. and the transmissivity of the well after simulation was 45,776 md-ft. (Equation 1 and Table 2). The transmissivity increase indicates improvements in permeability due to stimulation.

$$m = 0.1832\,(w\,v\,\mu / k H) \qquad \text{Equation 1}$$

Table 2. Transmissivity Calculation.

Pre-stimulation Transmissivity:	34,758	md-ft
Post Stimulation Transmissivity:	45776	md-ft

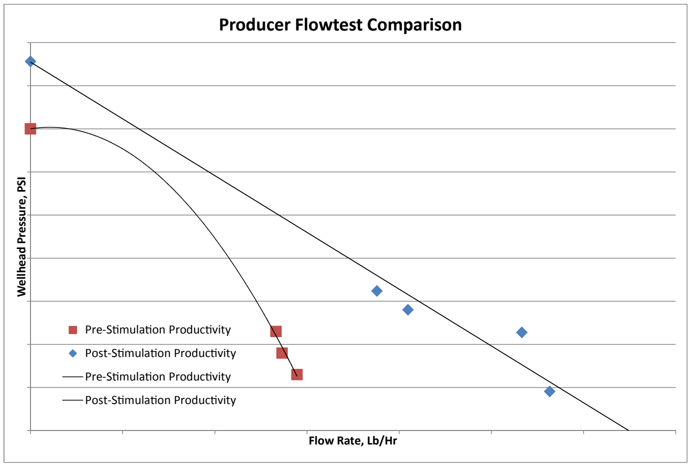

Figure 11. Flow Test Comparison.

Before the diverter stimulation, a temperature survey in the well indicated that two shallow steam zones were contributing the majority of the production. The post-stimulation survey showed that additional producing intervals were created and the existing production zones were enhanced (Figure 12).

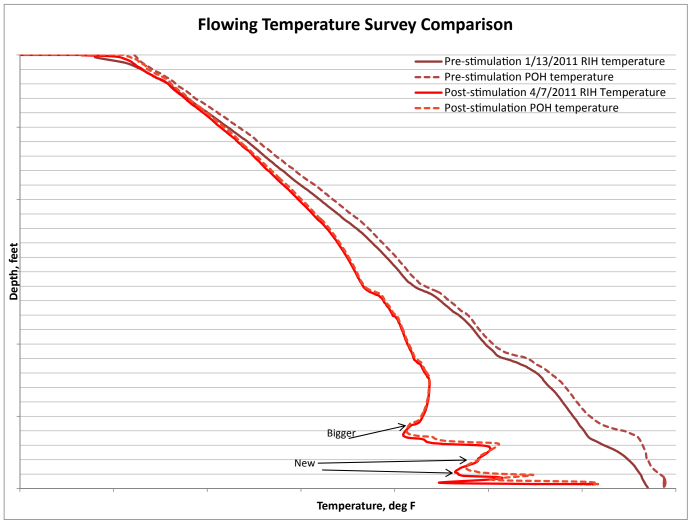

Figure 12. Flowing Survey Comparison

Two new seismic stations were installed for the purpose of monitoring the stimulation. Nineteen seismic events (M<1.5) were observed during the stimulation. Earthquakes that occurred in the monitored region up to one month prior to the stimulation were relocated to determine the extent of background seismicity.

Detailed analysis (Figure 13) concluded that five events (M 0.8-1.1) within 460 feet meters of the existing wellbore are caused by diverter stimulation.

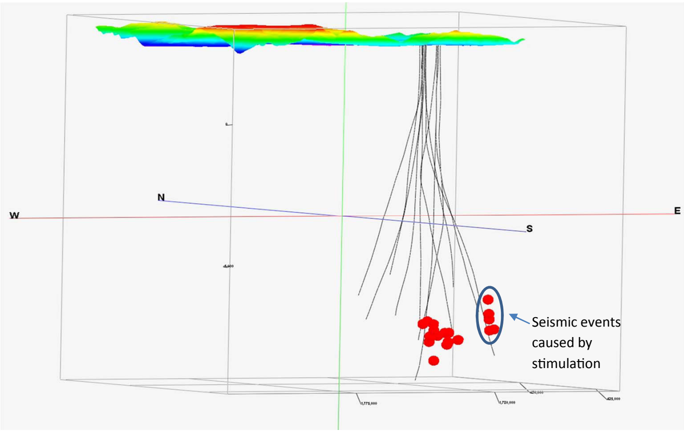

Figure 13. Microseismic response during diverter stimulation.

Conclusions

The goals of the first field trial of AltaRock' proprietary diverter materials have been successfully met and experiences gained paved the way for further full-scale diverter stimulation demonstration. The test showed that highly permeable fractures could be temporarily sealed with a chemical diversion system. The test also proved that the presence of a slotted liner did not pose a problem to proper diverter placement. Thirdly, results from the test showed that the injection profile in well could be modified temporarily and that fluid injection could be pushed deeper into the wellbore. Finally, transmissivity calculations (kh) before and after the test imply full degradation of the diverter material since the value held steady at approximately 55,000 md-ft.

The effectiveness of the proprietary diverter technology was further demonstrated at the second field stimulation by successfully improving productivity. Four weeks after the stimulation, the well continued to exhibit a 68% improvement in overall power production. The tracer results concluded that diverters effectively sealed existing permeable pathways to enable the creation of new fractures. The change in productivity curve shape indicated that more steam production is obtainable at the same wellhead pressure. The flowing temperature survey comparison showed increased steam production at pre-existing zones and that additional steam production zones formed deeper in the reservoir. Microseismic analysis was able to map events related to diverter stimulation, affirming hydroshearing of multiple fractures in the stimulated wellbore.

Table 3. Summary of Diverter Injector Test Results

	Injectivity, gpm/psi	Permeability-thickness (kh), md-ft	Permeability, md	Injection Zones	Fluid Level, compared with pre-test
Before Diverter Test	1.7	55,021	67.1	4 injection zones	Datum
One day after Diverter Test	0.75	54,731	91.2	4 injection zones	150 ft higher
Two weeks after Diverter Test	0.85	54,302	181	1 injection zone	230 ft lower

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[1]AltaRock Energy Inc. holds a portfolio of intellectual property, including patents and patent applications protecting its proprietary technology and methods