Disclaimer

This report was prepared as an account of work sponsored by the Department of Energy – Geothermal Technologies Program. Neither the Department of Energy – Geothermal Technologies Program, nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the Department of Energy – Geothermal Technologies Program or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the Department of Energy – Geothermal Technologies Program or any agency thereof.
Abstract

CSI Technologies, in conjunction with Alta Rock Energy and the University of Utah have undergone a study investigating materials and mechanisms with potential for use in Enhanced Geothermal Systems wells as temporary diverters or lost circulation materials. Studies were also conducted with regards to particle size distribution and sealing effectiveness using a lab-scale slot testing apparatus to simulate fractures. From the slot testing a numerical correlation was developed to determine the optimal PSD for a given fracture size. Field trials conducted using materials from this study were also successful.
# Table of Contents

Disclaimer ...................................................................................................................................................... 2  
Abstract .......................................................................................................................................................... 3  
Table of Contents ............................................................................................................................................ 4  
Introduction ................................................................................................................................................... 5  
Project Objectives .......................................................................................................................................... 6  
Phase I Major Findings and Conclusions ........................................................................................................ 7  
Phase I Results and Discussion ........................................................................................................................ 8  
   Candidate Materials and Degradation ........................................................................................................ 8  
   Identification of Candidate Materials or Processes ................................................................................. 8  
   Preliminary Screening of Materials ........................................................................................................... 8  
   LCM/Diverter Durability/Degradation Kinetics Under Static Conditions ................................................... 12  
Slot Testing .................................................................................................................................................... 14  
   Fabricate Static Slot Testers ...................................................................................................................... 14  
   Optimize Particle Size Distribution (PSD) for Different Fracture Apertures .............................................. 16  
   LCM/Diverter Durability/Degradation Kinetics Under Static Conditions ................................................ 19  
   Develop Prototype Lab-Scale Dynamic Flow Diversion Reactor ............................................................... 21  
Field Trials ................................................................................................................................................... 22  
   Test Performance of Successful Phase I Materials in Field Applications ................................................. 22  
Recommendations for Future Work ................................................................................................................ 22  
   Go/No-Go Decisions ................................................................................................................................. 22  
Appendix - Technical Paper ........................................................................................................................ 23  
   “Temporary Diverters for EGS Reservoir Optimization – Field Applications” ......................................... 24
Introduction

Enhanced Geothermal Systems (EGS) are typically comprised of wellbores drilled into dry, low-permeability formations that exhibit abnormally high thermal gradient. Water injected into these abnormally hot formations is heated and produced to the surface. The heat extracted from the rock formation by this water is used to generate power. Typical rock formations suitable for EGS operation are highly fractured. These existing fractures can create difficulty during drilling and completion, but are essential to the successful production and operation of EGS wells.

The existing fractures can pose problems during drilling when the wellbore intersects a fracture. The fracture can open due to drilling fluid hydrostatic pressure thus creating an alternative flow path for drilling fluid. The loss of drilling fluid from the wellbore into an open fracture, termed lost circulation, reduces drilling effectiveness and hinders subsequent completion operations. Common oilfield practice when lost circulation is encountered is to plug the fracture with sealant termed lost circulation material (LCM). LCM can be a particulate plugging material or a settable liquid. This practice is not viable in EGS reservoirs, however, due to temperatures encountered, as well as the fact that the very fractures that cause drilling fluid losses are later required to be flow paths between EGS wells.

Once the EGS well is drilled to target depth, the reservoir rock formations must be hydraulically stimulated in order to create or enhance the permeability. In the hydraulic stimulation process, water is injected into a well under high pressure sufficient enough to open existing fractures that intersect the wellbore. Once the pore pressure increases, fractures will slip due to existing stress in the rock. As the fracture faces shift, the irregularities in the fracture faces will not permit them to re-close completely, leaving a higher permeability flow path for injected water. These opened fractures create the resulting permeability increase. This fracture treatment differs from conventional Oil and Gas (O&G) stimulation processes in several ways. First, for O&G stimulation the pressure is raised so that tensile failure of the rock occurs but in EGS stimulation existing fractures are opened and stimulated through hydro-shear dilation, a process in which pressure is not raised sufficiently to cause tensile failure of the rock. Also, O&G stimulation typically involves pumping sand laden viscous fluid into the fracture to prop it open, while for EGS stimulation typically only water is pumped.

The hydraulic stimulation process for EGS wells is difficult to control due to long open wellbore intervals that intersect a large number of fractures. Fractures are held closed by in situ stresses acting on the formation. Slight variations in these in situ stresses caused by depth, variance in fracture orientation, localized mechanical property variations in the reservoir rock, etc. dictate that some of the fractures open with less hydraulic pressure than others. Typically the fractures at the shallower depths will open at lower pressure than those deeper in the well. Once the first fracture is opened, a significant portion of the injected fluid enters the opened fracture extending its open length. The next fracture to open in the wellbore will require additional flow rate and possibly a slightly higher pressure to overcome in situ stresses. Increasing pressure in the wellbore is difficult once the first fracture opens, since increasing pressure in the open fracture increases its fracture width which in turn increases its flow capacity thereby further reducing remaining wellbore fluid volume available to open new fractures.

The extreme temperatures encountered in EGS wells preclude use of oilfield mechanical packers to isolate portions of the borehole to selectively open new fractures. Seal failure or sticking of these mechanical devices can effectively ruin the entire wellbore. The extreme well temperatures also thwart use of common oilfield diversion agents (diverters) designed to plug unwanted fluid injection into portions of a hydrocarbon reservoir and thereby “divert” flow into other portions of the reservoir. Most organic polymers cannot withstand the application temperatures, and kinetics of removal processes for inorganic materials are extremely difficult to control at EGS application temperatures. Specifically, diverters will allow for the stimulation of multiple fractures on a given well, increasing the flow and producing capacity on a per well basis. This increase in productivity could significantly reduce the cost of EGS power production by reducing the number of wells needed to provide a given amount of flow and power production.
**Project Objectives**

The objective of this project is to develop efficient and affordable methods to temporarily plug flow into fractures intersecting EGS wellbores. Additionally, the diversion methods developed via this project will include a diverter degradation mechanism whereby the LCM/diverter material can be dissolved or degraded after an appropriate exposure time at EGS reservoir static temperature and be completely removed from the opened fractures. Application of these targeted fracture flow diversion methods will result in more effective EGS drilling operations and will allow increases in EGS heat transfer efficiency without inducing permanent system permeability damage.

This project encompasses:

- The identification of possible materials and mechanisms capable of functioning as LCM or diverters that withstand EGS temperature conditions
- The identification of potential degradation mechanisms and application pathways for removing these materials including thermal decomposition
- The laboratory evaluation of material durability and degradation mechanism kinetics of various candidate materials/systems at EGS temperatures
- The design and fabrication of a high-temperature slot apparatus to test the sealing performance of candidate materials in the laboratory
- Quantification of slot sealing performance vs. material properties, particle size range and distribution, concentration, etc.
- Development of design protocols for field applications
- The design and fabrication of a high-temperature flow reactor for testing the performance of LCM/diverter systems in the laboratory
- The yearly field testing of fluid diversion agents as they evolve from the laboratory investigations

This report details only Phase I of the project. Phases II and III of the program were not funded.
Phase I Major Findings and Conclusions

1. Literature study findings led to the identification of 34 materials to test in preliminary screening.
2. Fifteen of the 34 materials passed the initial screening tests.
3. Four materials met the diversion requirements with minimal potential (<15% residue) for formation damage after testing for 12 weeks at formation temperatures.
4. Three materials met the diversion requirements and degraded completely leaving less than 1% of residue after 10 weeks at formation temperatures.
5. The remaining eight samples did not degrade well enough at formation temperatures and were considered damaging to the formation.
6. An apparatus for testing and comparing sealing effectiveness with particle size distributions, slot sizes, and materials has been developed for testing at ambient temperatures.
7. Particle size distributions can be tailored for different fracture apertures to achieve acceptable sealing effectiveness.
8. A numerical correlation has been developed to determine diversion effectiveness as a function of particle size distribution and size variations in fracture apertures.
9. Mechanical properties of a material can affect diversion efficiency; however, more testing needs to be done before it can be included in the numerical correlation.
10. An apparatus for testing and comparing sealing effectiveness with particle size distributions, slot sizes, and materials has been developed for testing long-term at high temperature.
11. Several potential LCM/diverters are in the process of being tested to ensure their sealing capabilities. These will cover several different types of materials for different temperature range applications.
12. A temporary diverter was tested successfully in field trials and resulted in an increase in production flow rates and a 68% improvement in overall power production.
13. A prototype for a bench scale flow reactor to be used for testing a diverter’s sealing effectiveness under dynamic conditions was under construction, but the project was terminated before the reactor could be completed.
Phase I Results and Discussion

Candidate Materials and Degradation

Identification of Candidate Materials or Processes

Tasks

• Review literature documenting high-temperature material development as well as internally conducted development results. Survey current efforts by researchers working on high-temperature materials.
• Identify diversion/degradation mechanisms and pathways with potential to work as permanent or temporary diverters under the temperature conditions of EGS wells. Rank potential for success considering application conditions. Choose candidate materials to be tested in Phase I.

Results and Discussion

A literature review was conducted focusing on past and present methods and materials in the areas of lost circulation, stimulation, and diversion in the oil and gas, as well as the geothermal industry. From this review the following conclusions were made:

• Material needs to form a seal at the opening of the fracture to prevent further injection and further growth of the fracture
• A seal at the opening of the fracture can be formed by including larger and more fibrous materials which form a net across the opening that will catch the smaller particles which will complete the seal
• The optimal seal is a function of the fracture size and shape; if its dimensions are known, the material can be designed accordingly using previous research and modeling studies for reference
• A combination of materials with different shapes, particle size distributions, and degree of hardness will generally form the best seal and is the recommended approach if fracture characteristics are not known
• Maximum flow rates will form the best seal
• Some organic materials tend to leave a "burnt sugar" residue behind when exposed to high temperatures, so these materials may not be appropriate for EGS; inorganic materials with high melting points and low water solubility may be more appropriate
• Organic compounds and biopolymers such as polylactic acid (PLA) that hydrolyze into soluble non-damaging by-products may be better suited for this application
• Many of the current biopolymers cannot withstand geostatic temperatures and may not be suitable for use as LCM, but they may be applicable as EGS diverters if the wellbore is cooled sufficiently during the stimulation treatment (when the seal is needed) and then heats up rapidly once stimulation is completed. This would allow for fast and complete degradation of the diverter.
• Newer biopolymers are also being developed with better temperature resistance and could have application to be used as LCM and diverters in even hotter EGS wells.

Preliminary Screening of Materials

Tasks

• Expose specimens of each candidate LCM/diverter to water in pressurized autoclaves heated to temperatures ranging from 160°F (71°C) to 300°F (150°C). Periodically remove and weigh to determine degradation.
• Expose specimens of each system to water in pressurized autoclaves heated to temperature of 572°F (300°C). Periodically remove and weigh to determine degradation. Materials that completely dissolve/degrade are defined as having no “damage” capability.

Results and Discussion

Taking into account the conclusions from the literature review, a search of materials was conducted, focusing on melting point, solubility, mechanical characteristics, cost, availability, and environmental hazards of the materials. Thirty-four materials were chosen, and were almost evenly divided between organic and inorganic materials.

Of the 34 materials chosen, each was screened for degradation at the one of the lower test temperatures to determine whether or not to continue at higher temperatures (See Table 1). Initial test temperatures were determined based on the melting point and solubility of each material. If a material met the degradation requirements for the initial test temperature, it was tested again at the next highest temperature. If the sample met the initial requirements for all temperatures, testing was continued long-term for durability and formation damaging potential (See Degradation Criteria, Table 2).

Table 1. Test Temperatures

<table>
<thead>
<tr>
<th>Temperature</th>
<th>Materials Screened</th>
<th>Test Medium</th>
</tr>
</thead>
<tbody>
<tr>
<td>190°F</td>
<td>18</td>
<td>Atmospheric Water Bath</td>
</tr>
<tr>
<td>300°F</td>
<td>21</td>
<td>Pressurized Curing Chamber</td>
</tr>
<tr>
<td>500°F</td>
<td>15</td>
<td>Pressurized Curing Chamber</td>
</tr>
<tr>
<td>600°F</td>
<td>15</td>
<td>Pressurized Curing Chamber</td>
</tr>
</tbody>
</table>

For the curing chamber testing, dry samples were placed in ceramic tubes and filled with water. Tubes were loosely capped and placed in the curing chamber. The chamber was then sealed, filled with water, pressurized and set at the appropriate temperature. Samples were cured for 2 weeks. At the end of the two weeks the chamber was cooled, drained, and opened. Samples were removed, filtered, dried, and weighed. For long-term testing, any remaining sample was then returned to its ceramic tube and tested for another two weeks.

For the water bath testing, samples were place in loosely capped centrifuge tubes and placed in the water bath for 1 week. Samples were then removed, filtered, dried, and weighed.

Table 2. Degradation Criteria

<table>
<thead>
<tr>
<th>Temperature</th>
<th>Prescreen Requirements</th>
<th>Long-term Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>190°F</td>
<td>&lt; 30% degraded at 2 weeks</td>
<td>N/A</td>
</tr>
<tr>
<td>300°F</td>
<td>&lt; 50% degraded at 2 weeks</td>
<td>N/A</td>
</tr>
<tr>
<td>500°F</td>
<td>&gt; 50% degraded at 2 weeks</td>
<td>&gt; 60% degraded at 6 weeks</td>
</tr>
<tr>
<td>600°F</td>
<td>&gt; 50% degraded at 2 weeks</td>
<td>&gt; 80% degraded at 12 weeks</td>
</tr>
</tbody>
</table>

Eighteen materials were tested at 190°F. The majority of these samples were more than 50% degraded after two weeks and their testing was terminated (See Figure 1). Samples less than 30% degraded at 2 weeks were then tested at 300°F along with more temperature resistant samples not yet tested (See Figure 2). Samples that failed at this temperature were also discontinued (See Figure 3). Fifteen of the 21 samples tested at 300°F met initial requirements. Those samples were tested at the higher temperatures for degradation and formation damage potential (See Table 3).

Table 3. Passing and Failing Materials

<table>
<thead>
<tr>
<th></th>
<th>190°F</th>
<th>300°F</th>
<th>500/600°F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Tested</td>
<td>18</td>
<td>21</td>
<td>15</td>
</tr>
<tr>
<td>Failing Materials</td>
<td>13</td>
<td>6</td>
<td>8</td>
</tr>
<tr>
<td>Passing Materials</td>
<td>5</td>
<td>15</td>
<td>7</td>
</tr>
</tbody>
</table>
Figure 1. Failed Materials at 190°F

Figure 2. Passing Materials at 190°F
Figure 3. Failed Materials at 300°F

Figure 4. Passing Materials at 300°F
LCM/Diverter Durability/Degradation Kinetics Under Static Conditions

**Tasks**

- Expose potential LCM/diverter materials and systems in water to estimated EGS reservoir temperatures. Periodically remove specimens from the autoclave and weigh to determine extent of degradation. Calculate degradation rate and determine that candidate materials or systems completely degrade/dissolve leaving no damage.

**Results and Discussion**

Samples that met the lower test temperature requirements were tested at the higher temperatures for long-term degradation. Fifteen materials passed the initial screening requirements. Of those samples, seven materials showed the most potential. All seven materials were organic in nature, but actually showed less formation damaging potential than the other eight inorganic samples. Three of the seven promising materials showed complete degradation. The other four showed minimal formation damage (See Charts 5 and 6). The remaining eight samples did not degrade enough and were considered damaging to the formation (See Chart 7).

**Figure 5. Passing Materials at 600°F**

![Passing Materials at 600°F](image-url)
Figure 6. Passing Materials at 500°F

Figure 7. Failed Materials at 500°F
Slot Testing

Fabricate Static Slot Testers

Tasks

• Assemble a series of high-temperature static slot test devices to simulate fractures, as illustrated in Figure 1. Testers are equipped with a series of interchangeable slotted ends of various apertures ranging from 1/16 inch to ½ inch.

Results and Discussion

Components for the short term slot testing apparatus were ordered from a variety of vendors and modified as necessary to create the slot testing apparatus (See Figure 8).

Figure 8. Short-term Slot Testing Apparatus

One and three millimeter width slot sizes were available for testing purposes. All slot sizes were 1.5 inches in length.
As with the short term apparatus, components used to make the long-term slot testing apparatus were ordered from a variety of vendors and modified as needed (See Figure 9).

**Figure 9. Long-term Slot Testing Apparatus**

One and three millimeter width slot sizes were available for testing purposes, but only one millimeter slots were used for all tests performed. All slot sizes were 1.5 inches in length. The apparatus is capable of temperatures up to 500°F and holding that temperature for an extended period of time. It is also capable of approximately 1000 psi of working pressure. Due to the high pressure and extremely high temperature, this apparatus was actually very challenging to build and had to be redesigned several times before a successful experiment could be obtained. Due to these difficulties, test data is limited.
Optimize Particle Size Distribution (PSD) for Different Fracture Apertures

Tasks

- Choose a particulate material (probably sand) that can be easily sized over a wide range of particle size distribution. Formulate a series of blends of varying PSD. Measure diversion efficiency of blends as a function of slot width using static slot testers.
- Establish diversion efficiency correlation between particle size distribution, $D_{50}$, $D_{max}$, and $D_{min}$ and slot width. Calculate optimum particle size distribution for several slot widths.
- Confirm optimized PSD correlation via slot tests with appropriate slot apertures and PSD material.
- Repeat process with at least two other materials with different mechanical properties to correlate performance to Young’s Modulus.

Results and Discussion

The procedure for testing is a complicated process that through much trial and error, developed into a very efficient and repeatable way to test different particle size distributions. The following describes the procedure as it is used currently.

A particle size distribution (PSD) is weighed with an accuracy of plus or minus .005 grams. The sizes used in making the PSD varied according to slot size, but the following US mesh sizes were available: 6, 8, 12, 16, 20, 30, 35, 40, 45, 50, 60, 70, 80, 100, 140, 170, 200, 325, 400, >400. The PSD was then added to a specified amount of water and allowed to condition for 30 minutes to ensure that all the material became water wet. Different volume percentages of the PSD were added to the water and varied per slot size and type of material. The water and PSD slurry was then added to the upper test cell and all tubing was connected. Pressure was applied to the top of the cell at a specific psi and then the ball valve between the two collection vessels was opened. The time it took for the differential gauge to equalize was then recorded.

Standard sand tested first on a 1mm wide slot. Several different particle sizes were tested at a constant concentration, approximately 0.0646 ml of PSD/ml of water. The density of the sand used was 2.65 g/ml. Particle sizes used ranged from 16 mesh to >400 mesh and were combined in many different PSDs. Testing showed that different PSDs diverted effectively, but some diverted better than others. For this particular slot size, it was observed that distributions with no particles larger than the 1 mm would still divert effectively.

Standard sand was also tested on a 3mm wide slot. As with the 1mm, several different particle sizes were tested at constant concentrations, but larger concentrations were also tested. The larger concentrations were necessary because the original concentration used in the 1 mm tests did not perform as well as expected in this larger slot opening. This also aided in developing the concentration portion of the correlation developed. PSDs used were actually very similar to the PSDs used in 1mm testing, however, they were expanded to include the larger particle sizes (6 to >400 mesh) needed for the larger slot size. The particle size phenomenon described above in the sand at 1mm section was not as prominently observed in the 3mm testing.

Other materials were tested on a 1mm slot as well. Two of these materials were polylactic acid (PLA) and calcium carbonate. The primary purpose of testing these materials was to determine if materials with different mechanical properties would affect a PSD’s ability to divert. The data was used to develop a term for the correlation that would help relate different materials. Testing was unfortunately limited for these two materials but enough was seen to determine that material mechanical properties, particularly material hardness and density, do play a significant role in a materials diversion effectiveness.
Using all the data collected, a correlation that compares PSD properties to flow resistance was developed. The individual pieces of the correlation are combinations of particle properties and slot testing apparatus, which crudely simulates real well and fracture conditions. The equation for the resistance to flow \( R_f \) is displayed below. It is the dependent variable and represents the performance of the PSD.

\[
R_f = \frac{\mu}{\Delta P} \times \frac{v}{W_f - D_{avg}}
\]

Where:

\[
v = \frac{Q}{A}
\]

And:

\[
\mu = \text{viscosity of fluid, lb}_m/(\text{in}^\ast\text{sec})
\]

\[
\Delta P = \text{differential pressure, psi}
\]

\[
v = \text{velocity, in/sec}
\]

\[
Q = \text{flow rate, in}^3/\text{sec}
\]

\[
A = \text{cross-sectional area of fracture, in}^2
\]

\[
W_f = \text{Width of fracture, in}
\]

\[
D_{avg} = \text{average particle size of PSD, in}
\]

The second term of the correlation is the independent variable, and is comprised of calculation specific to the properties of the PSD.

\[
\frac{PSD}{V_c} = \frac{\varepsilon}{1 - \varepsilon} \times \frac{D_{avg}^2}{W_f \times (D_{10} - D_{90})} \times \frac{1}{V_c}
\]

Where:

\[
V_c = \frac{\text{Volume of Divertor}}{\text{Volume of Water}}
\]

And:

\[
\varepsilon = \text{porosity of PSD}
\]

\[
D_{avg} = \text{average particle size of PSD, in}
\]

\[
W_f = \text{Width of fracture, in}
\]

\[
D_{10} = \text{The size of the particle at the 10th percentile of the PSD from large to small, in}
\]

\[
D_{90} = \text{The size of the particle at the 90th percentile of the PSD from large to small, in}
\]
When these terms are expressed graphically for the 1mm and 3mm data described above, the following plot and trend line are observed:

**Figure 10. Correlation Data**

![Figure 10. Correlation Data](image)

From this data and the equation, it can be seen that a low $R_f$ value will correspond with the data having good diversion effectiveness. And as one could imagine when looking at the equation for $\frac{\text{PSD}}{\text{PSD}}$, as porosity approaches zero, velocity in the system will approach zero, thus making $R_f$ have an intersection point at (0,0). When this is incorporated into the trend line generation, as it is in the figure above, a linear correlation between $R_f$ and $\frac{\text{PSD}}{\text{PSD}}$ is determined to be:

$$R_f = 0.0346 \times \frac{\text{PSD}}{\text{PSD}}$$

This relationship has an $r^2$ value equal to 0.3574, which under these circumstances for this project and this amount of data, is a relatively decent value.
LCM/Diverter Durability/Degradation Kinetics Under Static Conditions

Tasks

- Perform long-term static slot test with potential LCM/diverter systems. Testing consists of deposition of bridging material across appropriately-sized slot at application temperature.

Results and Discussion

The testing method used varied slightly from test to test, but the concept remained the same for all testing: determine how long a material with adequate diversion effectiveness could retain that effectiveness at the degradation temperature. Once in the cell, the differential pressure (determined from the short term testing) is placed between the testing cell and the collection vessel. The ball valve between the cell and vessel is then opened and allowed to run for around a minute, so that a diverter pack can form correctly. Heat is then applied to the testing cell. The first heat schedule is 300°F for two weeks and then 500°F until it fails or runs out of water. The second schedule heats the material straight to 500°F, where it remains until it fails or runs out of water. Every three to four days, the material’s ability to divert is tested by applying the same differential pressure as before between the testing cell and the collection vessel. The valve is opened as before and data is collected which depicts how the material has changed since the last test. Data collection is another area where tests have varied, although this variation was caused by CSI improving the equipment by observation. In the above figure depicting the apparatus, there is a differential gauge that ties directly above and below the testing cell. This has only recently been added and so a very limited amount of testing includes data measurement from the differential. Nevertheless, the current testing method includes using this differential in the following manor: when the ball valve is opened during testing, it is allowed to remain open for 5 or 10 seconds. This allows the differential pressure to be across the diverter pack. The ball valve is then closed and the time it takes the differential to equalize back to zero is recorded. The shorter the time, the less the material is diverting. The amount of fluid released from the 5 or 10 seconds the ball valve is open is also recorded. In earlier testing, only the amount of fluid collected was recorded. The next section displays the data collected by the testing performed to date.

A combination of Sorel Cement and Proprietary Fiber A was prepared for long term testing. This data was collected when the apparatus was in its primitive form, so no differential pressure data measurement data is available (See Table 4). This test also planned to use the 300°F for two weeks and then 500°F until completion heating schedule. Unfortunately, with this setup, we were unable to successfully conduct the 500°F test.

<table>
<thead>
<tr>
<th>Test</th>
<th>Time (Days)</th>
<th>Temperature (°F)</th>
<th>Filtrate Collected (ml)</th>
<th>Length of Time of Collection</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
<td>74</td>
<td>43</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>301</td>
<td>85</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>299</td>
<td>10</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>7</td>
<td>299</td>
<td>10</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>13</td>
<td>298</td>
<td>20</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>0</td>
<td>72</td>
<td>30</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>295</td>
<td>180</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>6</td>
<td>305</td>
<td>13</td>
<td>1</td>
</tr>
</tbody>
</table>

Proprietary Particulate Material A was tested on a straight to 500°F heating schedule. It was also tested before the differential gauges were installed so the amount of fluid collected is the only data collected. The material was capable of holding a seal at 500°F for two weeks. During our testing of this material, a valve broke at the two week mark of the test, causing the test to end. This test was also considered a success.
Calcium carbonate was also tested on the 300°F and then 500°F heating schedule. This material showed very good sealing capabilities during short-term testing, but degradation tests showed that it might not degrade fully in the time allowed. It was decided that the test should be run regardless, to determine if it would degrade enough to still be a viable option if needed. Again, only fluid collected data was recorded due to the differential not being installed yet. Table 5 below displays the data for review. This test was considered a failure because it did not degrade enough to allow a significant change in diversion in the allowed time. This is supported by degradation data as well.

Table 5. Calcium Carbonate Long-term Slot Test Data

<table>
<thead>
<tr>
<th>Date</th>
<th>Time</th>
<th>Temp</th>
<th>ml Recovered</th>
<th>Run Time (s)</th>
<th>ml Remaining</th>
</tr>
</thead>
<tbody>
<tr>
<td>9/1/2011</td>
<td>9:00</td>
<td>76</td>
<td>8</td>
<td>5</td>
<td>457</td>
</tr>
<tr>
<td>9/1/2011</td>
<td>11:00</td>
<td>300</td>
<td>15</td>
<td>5</td>
<td>442</td>
</tr>
<tr>
<td>9/6/2011</td>
<td>8:00</td>
<td>300</td>
<td>25</td>
<td>5</td>
<td>417</td>
</tr>
<tr>
<td>9/8/2011</td>
<td>9:15</td>
<td>300</td>
<td>20</td>
<td>5</td>
<td>397</td>
</tr>
<tr>
<td>9/15/2011</td>
<td>16:00</td>
<td>300</td>
<td>27</td>
<td>5</td>
<td>370</td>
</tr>
<tr>
<td>9/19/2011</td>
<td>8:45</td>
<td>500</td>
<td>19</td>
<td>5</td>
<td>351</td>
</tr>
<tr>
<td>9/22/2011</td>
<td>7:45</td>
<td>500</td>
<td>35</td>
<td>5</td>
<td>316</td>
</tr>
<tr>
<td>9/26/2011</td>
<td>8:00</td>
<td>500</td>
<td>35</td>
<td>10</td>
<td>281</td>
</tr>
<tr>
<td>9/29/2011</td>
<td>8:20</td>
<td>500</td>
<td>46</td>
<td>5</td>
<td>235</td>
</tr>
<tr>
<td>10/3/2011</td>
<td>8:50</td>
<td>500</td>
<td>12</td>
<td>5</td>
<td>223</td>
</tr>
<tr>
<td>10/10/2011</td>
<td>11:45</td>
<td>500</td>
<td>18</td>
<td>5</td>
<td>205</td>
</tr>
<tr>
<td>10/13/2011</td>
<td>9:00</td>
<td>500</td>
<td>17</td>
<td>5</td>
<td>188</td>
</tr>
<tr>
<td>10/17/2011</td>
<td>9:30</td>
<td>500</td>
<td>16</td>
<td>5</td>
<td>172</td>
</tr>
<tr>
<td>10/21/2011</td>
<td>8:05</td>
<td>500</td>
<td>50</td>
<td>10</td>
<td>122</td>
</tr>
<tr>
<td>10/24/2011</td>
<td>9:45</td>
<td>500</td>
<td>8</td>
<td>10</td>
<td>114</td>
</tr>
<tr>
<td>10/28/2011</td>
<td>10:00</td>
<td>500</td>
<td>2</td>
<td>30</td>
<td>112</td>
</tr>
<tr>
<td>11/1/2011</td>
<td>8:00</td>
<td>500</td>
<td>2</td>
<td>30</td>
<td>110</td>
</tr>
<tr>
<td>11/7/2011</td>
<td>14:00</td>
<td>500</td>
<td>2</td>
<td>10</td>
<td>108</td>
</tr>
</tbody>
</table>

Proprietary Particulate Material B was tested using the 300°F and then 500°F schedule. The material showed extremely good sealing characteristics when used in previously tested successful particle size distributions and was predicted to have good degradation at higher temperatures. During testing, it was shown that the material would hold its seal for 2 weeks at 300°F and then for at least two weeks afterwards at 500°F. The material then started to degrade enough to allow more flow through, and eventually degraded enough to no longer hold a differential. See the table below for results.

<table>
<thead>
<tr>
<th>Date</th>
<th>Time</th>
<th>Temp</th>
<th>ml Recovered</th>
<th>Run Time (s)</th>
<th>Time to Equalize</th>
<th>ml Remaining</th>
</tr>
</thead>
<tbody>
<tr>
<td>11/11/2011</td>
<td>11:00</td>
<td>76</td>
<td>100</td>
<td>5</td>
<td>0</td>
<td>365</td>
</tr>
<tr>
<td>11/14/2011</td>
<td>8:00</td>
<td>300</td>
<td>0</td>
<td>5</td>
<td>20</td>
<td>365</td>
</tr>
<tr>
<td>11/18/2011</td>
<td>14:00</td>
<td>300</td>
<td>0</td>
<td>10</td>
<td>480</td>
<td>365</td>
</tr>
<tr>
<td>11/21/2011</td>
<td>9:30</td>
<td>300</td>
<td>0</td>
<td>5</td>
<td>420</td>
<td>365</td>
</tr>
<tr>
<td>11/28/2011</td>
<td>10:30</td>
<td>300</td>
<td>0</td>
<td>5</td>
<td>366</td>
<td>365</td>
</tr>
<tr>
<td>11/29/2011</td>
<td>10:00</td>
<td>500</td>
<td>0</td>
<td>0</td>
<td>No Test, 300-500</td>
<td>365</td>
</tr>
<tr>
<td>12/2/2011</td>
<td>10:30</td>
<td>500</td>
<td>0</td>
<td>20</td>
<td>200</td>
<td>365</td>
</tr>
<tr>
<td>12/13/2011</td>
<td>9:30</td>
<td>500</td>
<td>125</td>
<td>120</td>
<td>0</td>
<td>240</td>
</tr>
<tr>
<td>12/14/2011</td>
<td>9:30</td>
<td>500</td>
<td>5</td>
<td>10</td>
<td>0</td>
<td>235</td>
</tr>
</tbody>
</table>
Develop Prototype Lab-Scale Dynamic Flow Diversion Reactor

**Tasks**

- Design and fabricate a lab-scale prototype dynamic model for testing LCM/diverters. The heated cell will contain slots that simulate fractures. The reactor will include a high pressure slurry pump as well as alternate flow pathways (complete with individual back pressure regulators) that will allow for sealing of slots and rerouting of fluids without shutting down flow.

**Results and Discussion**

A reactor for testing fluid diversion agents was under development by the University of Utah’s Energy and Geoscience Institute’s geothermal group. A sketch of the reactor design is shown in Figure 7 below. The project was terminated before the fabrication was complete. The figure shows in black the components that were purchased before the project was terminated. Shown in red are the components that remain to be purchased.

The system would be able to handle pressures up to 2,000 psi and temperatures up to 580° F. The reactor has one fluid entrance and two fluid exit paths. The back pressure of each path can be adjusted giving preferential flow to one fluid path. Diversion material may then be pumped into the reactor as a slurry. The material would then block either spaces between rock chips or slots in a metal disc, depending on the configuration. Once the diverter provides enough back pressure the flow will switch from one flow path to the other. The diversion agents that are being investigated are materials that will either decompose with temperature, with or without a breaking agent. The efficacy of diversion agents can be determined by measuring how well they divert flow from one path to the other and then how long it takes for the diversion agent to disappear at temperature and reestablish preexisting flow paths.

**Figure 7. Fluid Diversion Reactor Schematic**
Field Trials

Test Performance of Successful Phase I Materials in Field Applications

Tasks

• Near the end of the first year, conduct at least one field experiment in an EGS reservoir to demonstrate temporary bridging effectiveness of any materials or systems identified during Phase 1 testing.

Results and Discussion

A temporary diverter was successfully tested in field trials. Highly permeable existing fractures were sealed temporarily which allowed for stimulation and opening of new fractures. Once the diverter degraded, the diverter treatment resulted in an increase in production flow rates and a 68% improvement in overall power production (See technical paper, Appendix A).

Recommendations for Future Work

Go/No-Go Decisions

Tasks

• If, after the end of Phase 1, a suitable LCM or diverter with or without a degradation mechanism has not been demonstrated, abandon the project.

Results and Discussion

Significant discoveries were made in Phase I of this project with regards to high temperature diverter materials, optimization of particle size distributions, and a correlation between PSD and flow resistance. These discoveries show the potential for numerous technological advances with regards to Enhanced Geothermal Systems. Phase II would have been initiated if the project not been terminated due to lack of funding.
Appendix - Technical Paper
“Temporary Diverters for EGS Reservoir Optimization – Field Applications”

GRC Transactions, Vol. 35, 2011

Temporary Diverters for EGS Reservoir Optimization—Field Applications
Susan Petty, Daniel Bour, Yinl Nordin, and Laura Notziger
AltaRock Energy, Inc, Sausalito CA

Keywords
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 systems 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.

Figure 1. EGS Well with Single Fracture Network.

Figure 2. Multiple Fracture Creation with Open-Hole Packer.
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 well, 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 wells 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>
<thead>
<tr>
<th>Fluid Type</th>
<th>Temperature (°C)</th>
<th>Improvement</th>
<th>Cost of Power/2010 (cents/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flash</td>
<td>250</td>
<td>N/A</td>
<td>11.53</td>
</tr>
<tr>
<td>Flash</td>
<td>250</td>
<td>3x flow rate (40% less than the case above)</td>
<td>6.88</td>
</tr>
<tr>
<td>Binary</td>
<td>175</td>
<td>N/A</td>
<td>31.94</td>
</tr>
<tr>
<td>Binary</td>
<td>175</td>
<td>3x flow rate (50% less than the case above)</td>
<td>16.02</td>
</tr>
</tbody>
</table>

*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

Injecto Test

AlmaRock 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 build up 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 build up. (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 levered 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 282 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.](image1)

![Figure 6. Temperature versus depth showing the change in well profile pre and post-test.](image2)
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.](image)

A second injectivity test was performed one day after diversion to test the degradation of diverters. An injectivity of 0.75 gpm/pui 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/pui 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 temporarily 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 sweep 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. Diversion 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-P10H 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-P10H 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).
After stimulation, the wellhead pressure returned to initial shut-in conditions within 24 hours. A post-stimulation productivity flow test was then conducted at three different wellhead pressures using a 4 inch orifice plate and testing manifold. 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.

$$m = 0.1832 \text{ (wv}/\mu\text{kH})$$

Table 2. Transmissivity Calculation.

<table>
<thead>
<tr>
<th>Pre-stimulation Transmissivity:</th>
<th>34,758</th>
<th>md-ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Post Stimulation Transmissivity:</td>
<td>45,776</td>
<td>md-ft</td>
</tr>
</tbody>
</table>

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).

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’s 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 (kha) 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 hydrosealing of multiple fractures in the stimulated wellbore.

References


Table 3. Summary of Diverter Injector Test Results

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

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