Completion Design Considerations for a Horizontal Enhanced Geothermal System

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ABSTRACT

The petroleum industry has had considerable success in recent decades in developing unconventional shale plays using horizontal drilling and multi-zonal isolation and stimulation techniques to fracture tight formations to enable the commercial production of oil and gas. Similar well completions could be used in Enhanced Geothermal Systems (EGS) to create multiple fractures from horizontal wells. This study assesses whether well completion techniques used in the unconventional shale industry to create multi-stage fractures can be applied to an enhanced geothermal system, with a focus on the completion of the EGS injection well.

This study assumes an Enhanced Geothermal System (EGS) consisting of a central horizontal injection well flanked on each side by horizontal production wells, connected to the injection well by multiple fractures. The focus is on the design and completion of the horizontal well. For the purpose of developing design criteria, a reservoir temperature of 200°C (392°F) and an injection well flow rate of 87,000 barrels per day (160 kg/s), corresponding to production well flow rates of 43,500 barrels per day (80 kg/s) is assumed. The analysis found that 9-5/8″ 53.5 pounds per foot (ppf) P110 casing string with premium connections meets all design criteria for the horizontal section of injection well. A P110 grade is fairly common and is often used in horizontal sections of shale development wells in petroleum operations.

Next, several zonal isolation systems commonly used in the shale gas industry were evaluated. Three techniques were evaluated – a "plug and perf" design, a "sand and perf" design, and a "packer and port" design. A plug and perf system utilizes a cemented casing throughout the length of the injector wellbore. The sand and perf system is identical to the plug and perf system, but replaces packers with sand placed in the casing after stimulation to screen out the stimulated perforated zones and provide zonal isolation. The packer and port completion approach utilizes an open horizontal hole that zonally isolates areas through the use of external packers and a liner.

A review of technologies used in these systems was performed to determine if commercially available equipment from the petroleum industry could be used at the temperatures, pressures, and sizes encountered in geothermal settings. The study found no major technical barriers to employing shale gas multi-zonal completion techniques in a horizontal well in a geothermal setting for EGS development. For all techniques considered, temperature limitations of equipment are a concern. Commercially available equipment designed to operate at the high temperatures encountered in geothermal systems are available, but is generally unproven for geothermal applications. Based on the study, further evaluation of adapting oil and gas completion techniques to EGS is warranted.

Introduction

This report explores technology and operational techniques that can be adapted from the oil and gas industry's success in horizontal wellbore placement and multistage stimulation to the completion of horizontal geothermal wells

for the purpose of creating Enhanced Geothermal Systems (EGS). The study assesses the applicability of the oil and gas completion operations to the higher temperatures, high water production flow rates, and large-diameter completions required for geothermal electricity generation. The feasibility of and strategies for applying completion techniques similar to those used in shale gas, such as multi-stage "plug and perforate" and "packer and port" completions, in horizontal EGS wells are reviewed. The scope of this study is to determine various techniques used in the petroleum recovery industry that can be applied to an enhanced geothermal system with a focus on the completion of the injection well. The transferable techniques include but are not limited to currently available products, methods of stimulation, reservoir modeling, and reservoir condition monitoring. This project is a collaboration between NREL and the Colorado School of Mines (CSM) as part of Colorado SURGE (*SU*bsurface *R*esearch in *G*eothermal *E*nergy).

Gas and Oil Technologies Applicable to Geothermal Setting

The majority of the transferable technology from the oil industry to an EGS system comes from Steam Assisted Gravity Drainage (SAGD), High Pressure High Temperature (HPHT) wells, and especially from unconventional shale plays. The development of these techniques has driven high temperature completion technology.

As an example, SAGD technology is similar to an EGS system in reverse. A SAGD system utilizes two horizontal wellbores in which the upper wellbore is used to inject heat via steam, while the lower wellbore collects the reduced viscosity heavy oil. The temperatures that SAGD operate in are similar to the temperatures desired for an EGS (around 500°F). The components used in a SAGD often include open hole sliding sleeve systems with external packers similar to the "packer and port" completion technique explored in this project. The technique has become popular enough for these companies to stock an inventory of regularly purchased products for a variety of applications.

HPHT wells encountered in today's deep wells range up to 20,000 psi and over 500°F. This has pushed the technology of plugs and stimulation equipment and has developed modified techniques to overcome the pressure and temperature related problems. The list of companies supporting this type of well completion is extensive with products for nearly every application. These HPHT wells become more commonplace every year with numerous successful multi-stage stimulation projects; consequently making HPHT products readily available for purchase.

Unconventional shale plays often utilize long horizontal wells requiring multiple individually isolated zones (called "stages") for stimulation. Hydraulic fracturing on a horizontal plane has the benefit of using the in-situ stress fields of the rock to assist in fracture propagation. The direction of the horizontal well must be oriented in the direction of the highest horizontal stress to ensure the induced fracture are perpendicular to the wellbore which makes the fractures parallel to each other enhancing hydrocarbon recovery between fractures. Multi-stage fracturing is utilized in most drilled wells today in the United States.

Focus of This Study

The focus of this study is on the completion of a horizontal well in the system. The goal of the completion of the horizontal well is to be able to create multiple, hydraulically-isolated (i.e., independent, non-intersecting) fracture zones within the horizontal section of the well. The ability to use or adapt techniques and technology from the oil and gas industry to achieve this goal is explored. In order to do this, first the requirements for the horizontal completion in the context of the overall EGS requirements (temperature, flow rates, number of fractures, fracture spacing, pressures, etc.) are established. Next, a wellbore design that can meet these requirements is proposed. Finally, completion stimulation techniques and technologies from the oil and gas industry are discussed and their applicability to an EGS setting is evaluated.

Proposed Enhanced Geothermal System Design and Requirements

The enhanced geothermal system proposed in this report is a horizontal well intersecting multiple vertical fractures. The proposed horizontal EGS will utilize one injector well and multiple production wells to achieve a system capable of producing 5 Megawatts of electricity (MW_e) gross per production well. This is a typical per-well generation capacity in the hydrothermal industry and is a good benchmark for an EGS project that should be commercially feasible in today's market. The amount of heated fluid necessary to generate 5 MW_e (gross) is around 50,000 barrels per day (bpd) (~80 kg/s) depending on the production well temperature. Another consideration is that the intended longevity of the suggested HDR EGS is 20-30 years. To achieve the prospective flow rates over this time frame, the size of the reservoir must be considerably larger than that observed in previous EGS projects (e.g., the Fenton Hills project). The size of the reservoir can be increased by creating more induced fracture networks. A horizontal system provides the opportunity to hydraulically fracture numerous stages resulting in a reservoir that can support the prospective flows without sacrificing reservoir integrity.

The injection well will be drilled first followed by the reservoir stimulation. The azimuth of the horizontal section will be in the direction of minimum principal stress of the formation in an attempt to create transverse fractures in relation

to the wellbore. The stimulation of the reservoir's fracture network can be achieved using multiple techniques that will be investigated throughout this report. The fracture network will be mapped (for example: micro-seismically) to ensure the connectivity to the production wells. The placement of the producing wells is integral to the efficiency of the system. The production wells placement will depend upon the intersection of as many fractures as possible and the distance the fluid must travel through the reservoir before being produced. The connectivity of the wells establishes the flow rates achievable from the system for a given pressure drive, whereas the distance that the fluid travels through the reservoir determines the amount of useful heat that can be extracted from the rock by the fluid over the reservoir lifetime.

Injection Well Design

The design for the wells above and within the horizontal section will be identical for all three well completion techniques discussed below. Enhanced Geothermal Systems require higher flow rates than their oil and gas counterparts due to the relative energy content of the extracted fluids. This will result in larger ID of tubing or liners, larger and potentially higher strength casing designs (due to thermal cycling), higher risk of scaling and corrosive deterioration, and larger pumps. An EGS well should have an approximate lifespan of 30 years to be able to fiscally overcome these robust design requirements. The injection well design is broken into three parts: the well casing design, casing connections, and the cementing of the well.

Casing Design

To achieve the well's target lifetime of thirty years a robust casing design will be necessary. The casing used in a HDR EGS well will require corrosion resistance, temperature cycling stability, long term exposure to high temps, and a high burst and collapse strength. The casing design for the proposed central injection well is critical to the success of the EGS system. The casing must have the following properties:

- Large bore (diameter) consistent with the injection rates required for the EGS system
- Ability to withstand the highest anticipated fracture stimulation pressure and rates
- Ability to handle the high temperature conditions without burst, collapse, or tensile failure
- Ability to withstand the low temperature conditions when injecting water
- Ability to withstand stresses from thermal cycling between the high and low temperature conditions, especially regarding axial stress
- Casing connections that are leak-tight even under varying temperature conditions
- Casing connections that exceed the tensile strength needed for thermal cycling
- Corrosion resistance to any expected reservoir constituents such as CO_2.
- Simple as possible

Scale is not considered an issue as this will be for injection only. Erosion from stimulation is not likely except with the perforation/port channels. H_2S is not expected in the injection stream.

The design of the injection casing is based on 100,000 bbls per day injection. This means that a large diameter casing string would be required. For this report, 9-5/8", 10-3/4", and 11-3/4" were considered. Given the large tensile loads, a high grade casing string is desired. A P110 grade is common and is often used in horizontal sections of shale development wells in petroleum operations. It is used here because of the high fracture stimulation pressures. The casing strings considered in this report is shown in Table 1. This does not preclude any other design.

Material Properties

The material and performance properties are affected by elevated temperatures. In typical petroleum operations, the steel property changes are considered fixed. Actually, the changes can be considered subsumed within a design factor for typical petroleum temperatures. Depending upon the ultimate temperature for this system, this may be sufficient. However, there is data that indicates the magnitude of the property changes with temperature. The yield point, the coefficient of thermal expansion, and the modulus of elasticity are all affected. In addition, the hardness and toughness of the steel are affected too. The temperature effect on hardness depends upon the alloying agents in the steel. The toughness climbs from more brittle behavior to more ductile behavior as temperature climbs, leading to potential creep issues. This becomes dominant at elevated temperatures, especially when temperature exceeds half of the melting point, which should not be an issue in this proposed EGS system. Yield strength and modulus of elasticity have the highest impact in conventional design methods.

Table 1. Suggested Casing Strings.

OD (in)	WPF (lbf/ft)	Grade	ID (in)	Cross Sectional Area in^2	Tensile Strength (lbf)	Collapse Resistance (psi)	Pipe Body Burst (psi)
9.625	53.5	P110	8.535	15.54649	1,710,000	7,950	10,900
10.75	60.7	P110	9.66	17.47267	1,922,000	5,880	9,760
11.75	60.0	P110	10.772	17.29959	1,903,000	3,610	8,010

The yield point (YP) of a metal is considered that point at which the material no longer acts elastically to an impressed stress. This can be thought of as the point where the crystalline structure of the metal starts to slide past one another along the crystal boundaries. The metal, upon the release of the impressed stress no longer returns to the original dimensions but instead has a permanent change in dimension, a plastic deformation. The hotter the metal, the lower the stress required to cause the transition from elastic to plastic behavior. Given that the yield point is a factor in determining the burst, collapse, and tensile strengths, then those attributes are negatively impacted by increasing temperature too. This change in yield point has been measured in laboratories. In general, steel loses about 0.03% of its yield strength for each degree Fahrenheit above 68°F (20°C).

$$YP_{adjusted} = YP_{68°F}\left(1 - 0.0003\left[T - 68°F\right]\right) \tag{1}$$

The modulus of elasticity (E) sometimes called Young's Modulus, is the slope of the function of stress versus strain within the elastic limit on a stress/strain diagram. It is commonly set at 30,000,000 psi for steel. In reality, it varies with temperature. For the range of the temperatures expected with this proposed EGS system, the "E" value will vary from 30,000,000 psi to just under 29,000,000 psi. This will have a minor effect on the strength of the steel in burst and collapse. However, it does affect the thermal stress loading.

$$E = -5\times10^{-6}T^2 - 0.0011T + 30.127 \tag{2}$$

The coefficient of thermal expansion (α) is the measure of how a material changes dimensions with a temperature change. With steel, this is often considered a constant, too. The value is frequently set to $6.9\text{x}10^{-6}$ per °F, which is roughly its value at 145°F.

$$\alpha = -3\times10^{-6}T^2 + 0.0065T + 6.0183 \tag{3}$$

Casing will undergo induced stresses from thermal cycling. It is conservatively assumed that the casing is cemented or packers set to lock it in place at 70°F, the lowest temperature considered in the system (the injection fluid temperature). Then, upon cessation of injection fluid, the casing will expand upon heating to geothermal conditions. Given that it will be constrained either by cement or external packers, upon heating, the expansion forces will be considerable. Using the coefficient of thermal expansion times the modulus of elasticity for a given temperature gives a value of psi for every °F change. The thermally induced stress (σ) between the higher temperature and 70 °F can be determined by multiplying the change in temperature times that previous value. Then using the cross sectional area (which is assumed constant) times the thermal stress gives the thermal force over that temperature change.

$$\sigma = E\alpha\Delta T \tag{4}$$

Using the modulus of elasticity to determine the yield strength at a given temperature times the cross sectional area gives a tensile strength at that temperature (rounded to the nearest 1,000 lbf as per API standards). Steel is assumed to be homogenous and isotropic. Comparing the thermal force to the tensile strength gives a design factor. A design factor less than 1 means that the casing has gone beyond its yield point and is thermally yielded (plastic deformation). If thermal stress exceeds yield strength of casing, hot yielding occurs. Note, the casing could still be doing its function, and most likely it is; however, the casing state is beyond its elastic limit.

The horizontal section of the casing will be very close to zero axial load due to gravity as it is laying on the low side of the hole. Therefore, all of the tensile strength can be used to resist the thermal stress loads. There will be some induced axial loads due to stimulation or injection fluid friction that need analysis.

Casing Connections or Couplers

Another issue to consider in well design is the casing connections. The casing couplers require special attention in a geothermal well. In deep horizontal wells the couplings, as well as the casing, will undergo extreme axial, compressive, and bending stresses. Additionally, temperature cycling of the casing can cause failure due to thermally induced fatigue. These stresses will be concentrated in couplings due to the geometry of the design meaning that special attention should be paid to the connections when evaluating cyclic fatigue, especially at the first threads of the casing. The couplings and pins of the standard API type connections (STC, LTC, and BTC) are designed for tension loading although wellbore curvatures

tend to weaken the joint strength. An API Buttress connection is the most common coupling used today in geothermal wells. One issue is that these standard connections are typically weaker in tension than the pipe body itself. By upgrading to a "Premium" connection, the connection strength is equal to or greater than the pipe body strength, and hence, gives the maximum tensile strength for a given EGS system. Current technologies in "Premium" couplings are making them more viable for EGS applications, albeit at a higher cost.

Cementing

The cementing of casing in enhanced geothermal systems can offer unique challenges. The challenges associated with these geothermal wells include the corrosive nature of the formations where the reservoir resides, the very high temperatures the cement must endure, the acceleration of "setting" at high temperatures, and methods to ensure the cement covers the entirety of the casing. The expansion with temperature, the stresses induced by thermal cycling, and the cement-to-casing-to-rock bonding are issues that must also be addressed when selecting the proper cementing application in HDR EGS wells. The challenges associated with an effective long-lasting cementing job, the current availability of geothermal specific cement composition, and modern deep horizontal well cementing techniques are discussed.

The thermal cycling of cement and its casing counterpart is a problem associated with geothermal completions. The expansion coefficients of the casing and cement are nearly never the same, making the bond between the two a major source of concern. This separation introduces areas where corrosive materials can penetrated the exterior of the casing leading to further separation, in addition to diminishing the casing's anchoring strength. Measures to minimize temperature cycling should be considered. Pre-tensioning of the casing string prior to cementation can prove to be beneficial by limiting compression due the thermal expansion.

Cement design in EGS wells should include the consideration of common EGS reservoir characteristics. The temperature encountered in any EGS reservoir will decrease cement thickening times. The presence of corrosives will be unique to every reservoir and should be considered in the design to minimize corrosive damage to cement and casing. EGS reservoirs typically have low formation pore pressure that can lead to the loss of circulation fluids and cement. Consequently, the cement composition should inhibit in-situ fluid migration, have an appropriate thickening time, and be able to withstand the harsh conditions of an EGS well.

It is typical to use API Class G cement with additives to control properties of fresh or hardened cement slurry such as compressive strength, fluid loss control, consistency and thickening time *(Alp, et. al., 2013)*. Additives that have been proven to emphasize these attributes include silica flour or Ground Granulated Blast Furnace Slag (GGBFS). The latter item is a byproduct of iron production and can be used as an additive or substitute for traditional Portland cement. GGBFS has been found to decrease porosity, increase compressive strength, increase thickening times, minimize strength retrogression, and provide an elevated level of carbonation protection when used as an additive *(Alp, et. al., 2013)*. Lightweight, foamed cements have the advantage of low permeability, high compressive strength, increased ductility, and lower thermal conductivity compared to traditional cements *(Niggeman, et. al.)*. However, the long term suitability of these cements are still being evaluated. For the proposed EGS wells, since the design temperature is 200°C (400°F) or less, typical API Class G cement with appropriate additives would be sufficient. (Nelson and Guillot, 2006)

Corrosion Considerations

The presence of corrosive substances in the formation, in particular hydrogen sulfide and carbon dioxide gasses, will lead to accelerated deterioration of completion equipment. Corrosive deterioration will be of utmost concern considering the longevity desired. The presence of corrosive materials in the formation will change the metallurgy of the casing. Upon drilling and completing, the presence of these corrosive materials may be minimal, but over the course of a 30 year lifespan the underlying materials within the formation can become a major problem. A thorough analysis of the formation and it composition should be undertaken to understand potential corrosion over the life of the well.

The control of the corrosion will be determined by the quality of the cement, cementing procedure, casing protection, treatment of the fluid before re-injection, and the metallurgic composition of the down-hole assemblies. For the injection well, operational considerations should be made to minimize the introduction of corrosive chemicals.

Injection Well Completion Techniques

There are three injection well completion techniques considered for this study: "plug and perf", "sand and perf", and "packer and port". These techniques are all designed for the same purpose of creating a reservoir fracture network through hydraulic fracturing at multiple, hydraulically-isolated zones in the wellbore and are all performed in the horizontal section of the wellbore. The hydraulic fracturing proceeds one zone at a time (called "stages") using the various techniques. The differences in the three techniques considered are in the zonal isolation. The three methods will be further examined in following sections.

Stimulation and Perforation Considerations

The basis of an EGS requires the induced stimulation of fracture networks to connect the injection well to the producing well. The fracture network needs to be large enough to be able to heat a large volume of fluid flowing through at a high rate. The hydraulic fracturing of the reservoir will be initiated from the injector well. The production wells will then be drilled into the induced fracture network in order to recover the heated injected fluid. The volumes and flow rates will be based on the reservoir's temperature, the number of fractured zones, and the overall capability of the system.

The casing perforations or openings in an EGS well completion will require more total surface area than a comparable oil well. This is due strictly to the amount of fluid to be transferred through the wellbore. This can be accomplished by either perforating more holes or perforating larger holes. Perforating large hole is preferential due to the lower pressure required to push fluid through the perforation into the formation. A large amount of smaller holes could compromise the integrity of the casing and cement.

Plug and Perf Design

The "plug and perf" technique utilizes a cemented casing throughout the length of the injector wellbore. The formation is then stimulated using a multistage fracturing and perforating process. This process is the most technologically advanced technique proposed. This technique provides the best zonal isolation throughout the hydraulic fracturing process.

The first step of this technique is to case the entire wellbore from bottom hole to surface. This can be as one section or as a liner hung off in an intermediate casing string (typically vertically). This entire length of the casing from the vertical section through all of the horizontal section should then be cemented from toe to a sufficient height to isolate the pay zones in one procedure; this can be difficult due to the volume of cement, time needed to inject the volume, and temperature in the reservoir. After confirming wellbore integrity (pressure tests, cement bond logs, etc.) the formation is then perforated and stimulated in a single trip near the toe of the well creating the first stage. The perforation guns are pushed into place by pipe (coiled tubing (CT), workover strings, drill pipe, etc.). After stimulation, a retrievable or drillable packer is then installed above the first stage, the next stage is perforated, stimulated, and the process repeats until the desired number of stages are achieved. In some cases in the Bakken fields of North Dakota, over 40 stages have been accomplished.

This completion design will have the highest cost of the three proposed designs but offers the most technological security. The horizontal wellbore being cased and cemented ensures that the completion tools downhole are protected from any change in reservoir stability and downhole tools can be retrieved more easily than in an open hole if needed. Another disadvantage of this design is the time of installation. The completion equipment specific to this design are costly due to the amount of equipment needed to hydraulically fracture the reservoir. Each stage requires an individual wireline or CT trip down hole and back out which takes a considerable amount of time and is consequently costly.

An alternative to this process is to perforate all stages first, deploy the completion string consisting of ball-actuated fracturing valves and liner packers, then hydraulically fracture through the completion string (Figure 1). The completion string would essentially be the same as the previous method although the abrasion of the stimulation fluid with proppant may cause some premature degradation of the sliding sleeve system. The drop-ball acts to seal off the well downhole eliminating the need for packers inside the production string. The hydraulic fracture schedule will commence as follows: drop the first (smallest) ball to actuate valve nearest toe, pump prescribed hydraulic fluid and proppant, drop next size larger ball to actuate next valve and seal off downhole stages in production liner, pump prescribed hydraulic fluid and proppant, repeat until all stages are complete, retrieve or use degradable drop-balls, and drill out ball-catch assemblies if necessary.

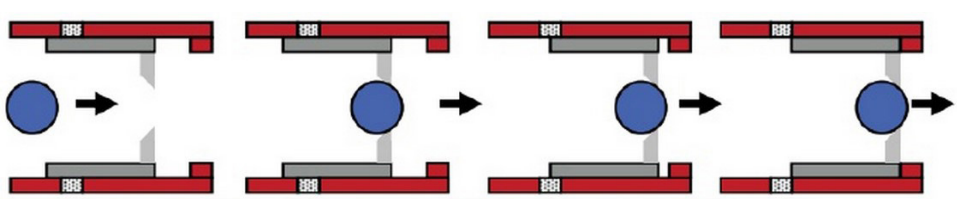

Figure 1. Schematic of Drop-ball Actuated Sliding Sleeve system. Sleeve is closed initially, ball is dropped, pressure is increased until sleeve opens, ball acts to isolate downhole stages. (Mathur, et. al., 2013).

The advantage of this alternative over the traditional "plug and perf" method is the decrease in the number of trips downhole to hydraulically fracture each stage. The stimulation of the individual stages can be performed without another trip downhole. A disadvantage of this alternative is the pressure increase needed to push the stimulation fluid through the sliding sleeve port before the perforations, in addition to the wear this puts on the sliding sleeve itself. Both designs will require that the stimulated stages align between the packers of the completion string. If the ball-catch assembly needs to be drilled out the zonal flow control is lost without intervention.

Sand and Perf Design

The "sand and perf" completion approach uses the same wellbore set-up as the "plug and perf" approach, but differs by the stimulation technique. This method uses a sand plug to isolated fractured stages rather than a retrievable packer.

This technique has the advantage of being technically simpler by eliminating the installation and removal of the isolating bridge plugs. This technique is popular in vertical wells as gravity helps deliver the sand to location and the sand maintains its position.

This stimulation method is similar the "plug and perf" method with the exception of using tightly packed sand in the place of the bridge plugs. This entire length of the wellbore should be cased and cemented from toe to a height sufficient to isolate the horizontal section in one procedure. The formation is then perforated and stimulated in a single trip near the toe of the well creating the first stage (Figure 2). An amount of sand is then injected into the wellbore to isolate the first stage from the next stage's stimulation. The next stage is perforated and hydraulically fractured followed by more sand to isolate the newly created stage. The process repeats until the desired number of stages are achieved. The sand must then be extracted up the wellbore. This is done through the use of a pressurized nozzle on coiled tubing to loosen the sand, suspend the sand in the fluid, and flush the sand/fluid mix out of the wellbore similar to the transportation of cuttings while drilling.

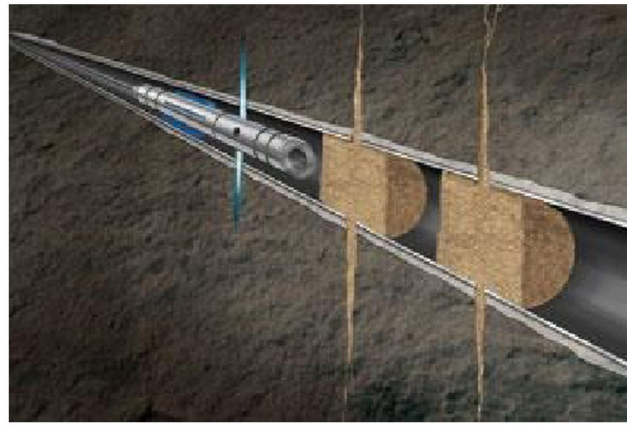

Figure 2. Sand and Perf technique for hydraulic fracturing. Once a stage has been fractured it is isolated with packed sand before perforation and stimulation of the next stage. (Mathur, et. al., 2013).

The horizontal wellbore design presents challenges to the efficiency of the "sand and perf" completion design. As sand is packed to isolate a stage the sand is inevitably forced into the fractures which can be problematic to flush. This is not as much of an issue for oil and gas wells as the hydraulic fracturing is performed in producing wells; the sand will naturally flush itself out as oil is produced; but in the case of fracturing through the injector the sand will be forced deeper in the fractures potentially plugging induced fractures. This technique is performed fairly easily in vertical wells since gravity assists the placement of the sand; however this is not the case in horizontal wells. The sand will tend to settle out in a horizontal wellbore making an effective zonal isolation problematic; the distance between induced fractures in an EGS setting could help alleviate this.

The advantages of the "sand and perf" method are the simplicity of the system. Mechanical packers can get prematurely stuck in the casing, can be difficult to remove if retrievable or need to be drilled out if drillable, and are costly when compared to sand plugs. There is also no trip downhole needed to set the sand plug. While the sand must be flushed out after the fracture schedule is complete, the time and cost is typically less than removing mechanical plugs.

Packer and Port Design

The "packer and port" completion approach considered utilizes an open horizontal hole that zonally isolates areas through the use of external packers and a liner. This method differs from the other two methods by not using cemented casing; hence eliminating the cost and tasks of casing, cementing, and perforating in the horizontal section. The individual stages would be hydraulically fractured one at a time through the use of the sliding sleeve ports or drop-ball valves.

The "packer and port" approach would be completed in the least amount of steps of any of the proposed techniques. The non-horizontal casing and cementing procedures of all three techniques will be identical; however the horizontal section of this approach will be left openhole. The openhole section will then be cleansed of drilling fluids before the completion string will be deployed. The completion string will consist of a production liner with numerous sliding sleeve ports and external packers to isolate individual stages. The process of setting the external packers involves either pressurizing the well (the specific procedure will be determined by the manufacturer of the equipment) or allowing the wellbore fluids to be imbibed into the elastomer seals, swelling the elastomer to isolate the different stages. Once the packers are set the stages are effectively isolated and the hydraulic fracturing process can begin. Hydraulic fracturing will commence through the sliding sleeve port system one stage at a time beginning at the toe.

This completion approach is the least involved of the three proposed techniques. The elimination of cemented casing in the horizontal section of the wellbore is a significant simplification of the completion system. The casing in the horizontal section endures the most significant corrosion potential of the overall casing design due to its direct exposure to the formation. The horizontal casing is also difficult to centralize, will undergo wear from remediation, and requires perforation. The hindrance of filling the annulus entirely with cement in the horizontal section is alleviated. The cost of completion is minimized with the "packer and port" system. Fractures can be initiated in each stage, nearly guaranteeing that each stage has at least one of its own fractures. This system also has advantage of using open hole in isolated section, so that the fracture can initiate at the "weakest point" in the formation, likely accessing an existing fracture in the formation.

There are some disadvantages to this approach that should be considered. This system utilizes sliding sleeve port sections on the production liner with external packers to seal the annulus. The zonal isolation of the induced fracture

network will be dependent on the external packers. The external packer to wellbore seal can prove troublesome for complete zonal isolation as the rough texture of the wellbore wall can create voids for fluids to transfer through. Induced fractures can initiate next to or behind the external packer creating failure in the zonal isolation as well. In addition, the external casing packers will need to withstand not only the temperatures and pressures without fluid bypassing, but also, they must resist the movement of the liner from thermal cycling. The length of the external elastomer can be varied and must be determined before deployment of this type of system.

Currently Available Applicable Completion Products

Completion products that are able to withstand the rigors of an EGS are currently being developed for oil and gas operations. Development of products to endure the challenges of these deep and long wells has made high temperature completion components available to the open market. While a majority of these products are built-to-suit and not "off-the-shelf," they are commercially available based on purchase orders. The products considered in this report has been limited to the components of the injection well of an EGS with a minimum reservoir temperature of 200°C (392°F).

Packers Plus has developed multiple completion tools applicable to an EGS. Their Inferno™ completion tools were specifically designed for an EGS system in the Cooper Basin of Australia *(Packers Plus, 2014)*. These components are designed to be capable of 315°C (600 °F) and 69 MPa (10,000 psi). The Inferno™ line of tools include bridge plugs, a sliding sleeve multi-stage completion system, and swellable packers up to 10 m (30 feet) in length.

Halliburton has developed their ThermaLock™ cement that is designed to retain its slurry weight under reservoir conditions, have high compressive strength, resist corrosion from CO_2, and have a working temperature range from 60°C (140°F) to 370°C (700°F). Halliburton has cementing techniques and equipment that has been proven in many high temperature fields worldwide.

ThermaSource Inc. is a cementing and drilling contractor involved in geothermal completions. ThermaSource has extensive cementing equipment and numerous cement blends specifically for geothermal applications. Numerous existing geothermal systems back the quality of this geothermal-specific service provider.

Schlumberger has a high-temperature cement that is designed to closely match the thermal expansion/contraction rate of casings rated up to 315°C (600°F). Schlumberger has a perforating gun and charges rated up to 260°C (500°F) known as the PowerJet™.

Baker Hughes has a strong presence in the SAGD completion tool market. Baker Hughes has an intelligent sliding sleeve system that is rated up to 260°C (500°F); the use of this product limits the number of stages to ten or less *(Gill, 2014)*. Weatherford has sliding sleeve systems that can operate up to 370°C (700°F). Weatherford has a coil-tubing deployed sandjet nozzle system used for perforating and stimulation. The SwageHammer packer is able to withstand 205°C (400°F).

GEODynamics has a wide variety of perforating systems with the most extreme HPHT charges ranging up to 274°C (525°F) for one hour and a 3.53 cm (1.39 inch) diameter perforation in a 9 5/8 inch casing known as the 7052 RAZOR® SBH Shape Charge *(Ambler, 2014)*. These charges are designed to withstand up to 315°C (600°F) for one hour and 288°C (550°F) for ten hours. *(GEODynamics, 2007)*

TAM International produces the FREECAP GT geothermal-specific swellable packer that can withstand temperatures up to 300°C (572°F).

WellTec has multi-elastomer mechanically-set packers that have an operating range up to 300°C (572°F).

Conclusions and Next Steps

Technology and operational techniques that can be adapted from the oil and gas industry's success in horizontal wellbore placement and multistage stimulation to the completion of horizontal geothermal wells for the purpose of creating Enhanced Geothermal Systems (EGS) were investigated. First, a well design for a horizontal injection well was proposed. The design assumed a reservoir temperature of 200°C (392°F) and an injection well flow rate of 87,000 barrels per day (160 kg/s). The analysis found that 9-5/8" 53.5 ppf P110 casing string meets all design criteria for the horizontal section of injection well. A P110 grade is a common oilfield grade and is often used in horizontal sections of shale development wells in petroleum operations. The study found that casing connections may be a weak point in the design, and that non-API premium casing connection should be considered.

Next, three techniques - plug and perf, sand and perf, and port and packer completions - were evaluated. The plug and perf technique would likely present the least technical risk, but would also be the most expensive option. Sand and perf completions would have similar advantages to plug and perf completions, but avoid the cost and difficulty of working with bridge plugs or isolation packers. However, the placement of sand in horizontal wells and potential for plugging the fractures created during stimulation could introduce additional difficulties. A port and packer system would likely be the simplest and fastest to implement from a technical standpoint and has several other advantages, such as avoiding the

need to cement the casing in the horizontal section in place. However, the ability of external packers to adequately isolate sections could be problematic due to the difficulty of forming a seal between the outside of the casing and the rough walls of the open borehole. For all techniques consider, temperature limitations of equipment is a concern. Commercially available equipment designed to operate at the high temperatures encountered in geothermal systems are available, but is generally unproven for geothermal applications. However, no major "showstoppers" were identified. Based on the study, further evaluation of adapting oil and gas completion techniques to EGS is warranted.

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