EGS Designs with Horizontal Wells, Multiple Stages, and Proppant

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ABSTRACT

In Enhanced Geothermal Systems (EGS), hydraulic stimulation is used to improve well productivity. EGS is typically performed in a nearly vertical well, in one stage, with no proppant. In the past several years, the oil and gas industry has achieved radical improvements in stimulation performance by using multiple stages, proppant, and horizontal (or deviated) wells. For the most part, these technologies have not been adopted in EGS. The EGS community is focused on the concept of "shear stimulation," injecting water to induced slip on self-propping natural fractures. As a result, proppant is viewed as being unnecessary or ineffective. The use of packers to enable multiple stages is considered technically infeasible because EGS wells are completed openhole (to maximize connectivity to natural fractures) and reliable openhole packers are not available at high temperature. In this paper, we discuss an EGS design that relies on creating new fractures, rather than stimulating natural fractures. In this design, a horizontal (or deviated) well is drilled and completed with cemented casing. Cased hole packers or bridge plugs are used for zonal isolation, allowing multiple stage fracture treatments to be pumped through perforations in the casing. Proppant is injected, possibly along with a viscosifying agent. We performed simple calculations to estimate the potential effect of multiple stages and proppant on the flow rate that can sustained through an EGS doublet. These calculations were intended to give rough estimates and provide a sensitivity analysis, not provide detailed analysis. We found that an EGS design with multiple stages and proppant should give dramatically improved economic performance relative to current designs. With enough stages, flow rate will be limited more by pressure loss in the wellbores than in the reservoir. We did not perform calculations on thermal breakthrough, but we expect that the use of multiple stages would help improve reservoir contact and prevent premature thermal breakthrough. We reviewed the literature in order to assess the technical viability of our proposed design. It was found that cased hole packers rated to geothermal temperatures are available with current technology. A review of EGS field experience shows that in the rare cases when proppants have been used, they have consistently improved well productivity, even in granite. There is some laboratory evidence to suggest proppants may chemically degrade over time at high temperature, but there is also evidence that certain coated proppants are resistant to degradation. The proposed design would increase cost but deliver radical improvements in flow rate (and revenue) per well.

1. INTRODUCTION

1.1 Introduction

Hydraulic stimulation was originally developed by the hydrocarbon industry (Montgomery and Smith, 2010). In the hydrocarbon industry it is believed that injection causes the initiation and propagation of new hydraulic fractures (Khristianovich and Zheltov, 1959; Economides and Nolte, 2000). Sand or other particular matter (called proppant) is injected with the fracturing fluid during treatment. The proppant remains in the fractures and allows them to retain transmissivity after pumping stops and the newly formed fractures close.

Hydraulic fractures form perpendicular to the local minimum principal stress (which is typically horizontal), and so in vertical wells, newly formed fractures will form axially along the wellbore. The advent of horizontal drilling enabled the creation of transverse fractures. In this design, a horizontal well is drilled in the direction of the minimum principal stress. Fractures form perpendicular to the orientation of the wellbore, which allows multiple fractures to be formed, creating additional contact with the formation.

Rather than injecting simultaneously into the entire reservoir interval of the well, individual sections (called stages) are hydraulically isolated with downhole tools, and pumping is performed sequentially into each stage. The advantage to using multiple stages (rather than injecting into the entire wellbore at once) is that it creates a more uniformly distributed fracture network. Once a fracture has formed at the wellbore, fluid tends to flow into that fracture, reducing wellbore pressure and preventing fractures from forming in other sections of the wellbore. With multiple stages, fractures are forced to form at each individual stage.

A variety of strategies are used for multiple stage completion in horizontal wells. In "plug and perf" completions, casing is cemented into the lateral prior to stimulation. A section near the "toe" of the wellbore (the section furthest from the wellhead) is perforated with explosive charges that blow holes through the casing (and surrounding cement) and connect the wellbore to the formation. Injection is then performed into the perforated section. Next, a plug is set inside the casing, hydraulically isolating the section that has been stimulated from the rest of the well. Perforation is then performed in the adjacent stage, and the process is repeated until the entire lateral has been stimulated.

In sliding sleeve completions, casing is placed in the production interval but not cemented. Openhole packers are used to isolate the annular sections of the wellbore (around the casing) and a system of valves is used to create isolation within the casing, so that each stage can be pumped sequentially.

The combination of horizontal drilling, multiple stages, and optimization of proppant strategy has created a revolution in the oil and gas industry over the past decade, enabling economically viable production from massive, low permeability oil and gas resources in very low permeability shale (King, 2010).

In Enhanced Geothermal Systems (EGS), hydraulic stimulation is used to increase formation permeability, most often in crystalline rock such as granite. In EGS, stimulation is typically performed by injecting fresh water (no proppant) into an openhole section of a vertical wellbore. It is generally believed that injection induces slip on natural fractures, which experience increased transmissivity in response to slip (Tester, 2006). One or more production wells are drilled, and fluid is circulated, heating as it flows through the formation.

The objective of EGS is to achieve economic production of energy from low permeability resources, precisely what the oil and gas industry has achieved in shale over the past decade. The strategies that have succeeded for oil and gas should be considered for EGS.

Nearly all EGS wells have been drilled vertical (or somewhat deviated), stimulated in a single stage, and have not used proppant. There are a few exceptions. The Newberry EGS project effectively had multiple stages because a thermally degrading chemical diverter was used (Petty et al., 2013). The Groβ Schönebeck project used a nearly horizontal well and used zonal isolation to perform a three stage stimulation in sandstone and volcanic rock (Zimmermann et al., 2010).

For this paper, we performed simple "back of the envelope" calculations to demonstrate the potential effects of multiple stages, horizontal drilling, and proppant on the performance of an Enhanced Geothermal System. The goal for economic EGS development is flow rates in the range of 100 kg/s at 200°C, sustained for a decade or more. Our calculations show that multiple hydraulic fracturing stages (and possibly the use of proppant) could lead to these levels of productivity. With enough stages, flow rate may be limited more by pressure gradient in the wellbore than in the reservoir.

EGS projects have not used multiple stages, proppant, and horizontal (or deviated) wells either (1) because it was believed that they would not be effective or (2) because of the technological challenges of operating at high temperature in hard rock. We have reviewed the literature to address these concerns. The review demonstrates the benefit of applying these technologies to EGS, even in granitic rock. Technical feasibility is less certain, but generally we found that the technology exists to apply these concepts at 200°C with current technology, provided the project was designed appropriately. We did not perform calculations on thermal breakthrough, but we expect that using additional stages would create more pathways for flow and delay thermal breakthrough. This may even allow for closer wellbore spacing, which would make it easier to establish good hydraulic connections between wells and higher flow rate. In practice, the number of stages and wellbore spacing would be chosen based on an optimization of cost and expected future production rate and temperature. In the future, we will repeat the analysis in this paper with a model that includes thermal drawdown.

Drilling horizontal wells, using multiple stages, and injecting proppant would increase cost. However, stimulation cost is a small part of the overall cost of an EGS project (Sanyal et al., 2007), and stimulation performance is one of the primary variables in determining project revenue. Drilling costs are a substantial proportion of EGS costs and more study would need to be performed to calculate the incremental cost from using deviated or horizontal wellbores.

The idea of using multiple stages in an EGS well has been proposed by others (Gringarten et al., 1975; Jung, 2013). Two new points emphasized in this paper are that: (1) completions with cemented casing could make zonal isolation for multiple fracturing stages possible with current technology and (2) the use of proppant should be considered, since field experience indicates it increases fracture transmissivity, even in granite.

1.2 Wellbore designs

Multiple stage completions require that each stage is separately by adequate distance in the direction perpendicular to the minimum principal stress (so that the fractures created at each stage do not overlap). Ideally this would be achieved with horizontal wells.

Horizontal drilling is technically challenging in hard rock and high temperature, and while it is technically possible, more study is needed to determine whether it would be cost effective. Steerable drilling systems are available at temperatures up to at least 300°C (Halliburton, 2013). Tools that allow precise geosteering are available to temperatures up to 180°C (Schlumberger, 2011), though in EGS precise geosteering is probably unnecessary. EGS projects are typically located in hard rock such as granite, but geothermal resources also exist in lithologies that are less challenging to drill.

If horizontal wells were not considered technically feasible, then deviated wells could still permit multiple transverse fractures to be formed. For example, a well deviated at 45° from vertical could achieve a 100 m horizontal spacing between each stage by spacing the stages at 141 m intervals along the wellbore. If necessary, wells could be deviated at shallower elevation than the target depth (where the temperature is lower and the lithology is easier to drill through). In a compressive stress regime, such as at Cooper Basin, hydraulic fractures form horizontally, and multiple transverse fractures could be created in a vertical well. Figure 1 shows schematics of multiple stage EGS doublets for (1) deviated wells in a normal or strike slip faulting regime and (2) vertical wells in a reverse faulting regime.
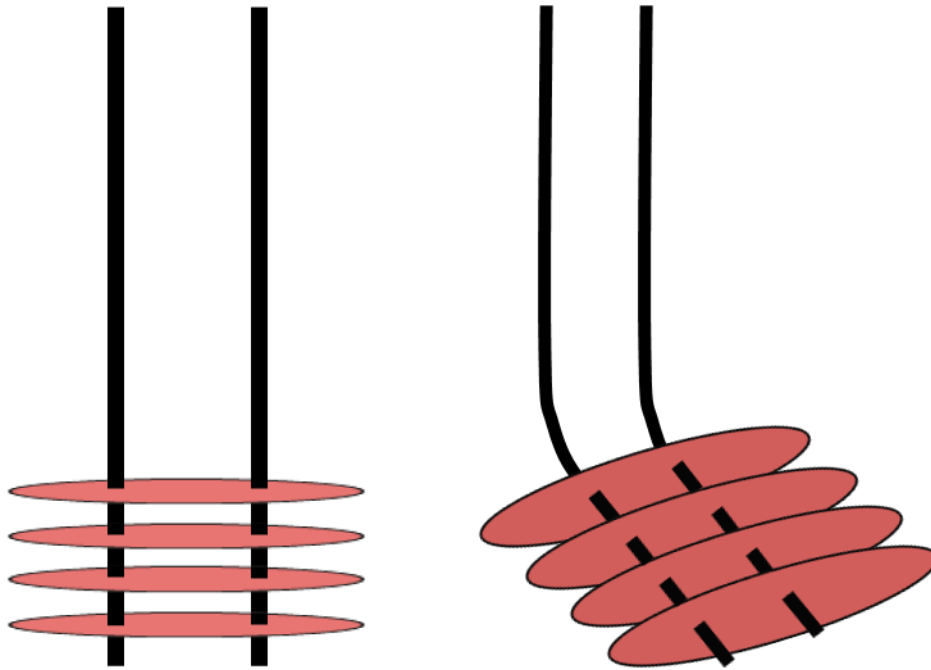
Figure 1: Multiple stage EGS concepts. On the left, horizontal fractures (forming in a reverse faulting regime) are stacked vertically. On the right, wells are deviated at an angle from vertical, placed side-by-side, and connected with vertical fractures (normal or strike slip faulting regime).

Ideally, there would be an identical flow rate in each stage. An imbalance could contribute to thermal short-circuiting. However, for the designs in Figure 1, a variety of factors may prevent the flow rate from being equal in each stage. Flow paths passing through the stages closest to the wellhead pass through a shorter length of the wellbore, and experience less pressure drop from flow through the wellbore. The stages at lesser depth are at lower temperature and stress. The lower temperature would cause the water circulating in the formation to have higher viscosity (in the cooled region of the formation), but the lower stress would increase the fracture transmissivity (because fracture aperture decreases in response to increasing normal stress). The thermosiphon effect driving flow (caused by the differing temperatures and densities of the fluid in the injector and production well) would encourage a greater flow rate through the deeper stages. Thermal cooling stresses would develop more rapidly in whichever stages were accepting a greater flow rate. To fully unpack these issues would require a detailed analysis.

A second issue with non-horizontal completions is that technologies for zonal isolation (required for multiple stages) will have a maximum temperature of operation. As deviated or vertical wells are drilled deeper through the producing interval, the formation temperature will increase until the maximum operating temperature for zonal isolation is reached. This issue would limit the practical length of the producing interval and require production from stages shallower (at lower temperature) than the maximum allowable temperature.

If horizontal wells can be drilled, we would propose to design an EGS doublet as shown in Figure 2. The vertical sections of the wells are on opposite sides of the lateral. With the wells in the doublet oriented from heel to toe, all flow paths through the system will pass through the same length of wellbore, reducing the tendency for unbalanced flow through stages. The entire producing interval is at the same temperature and stress, avoiding the potential consequences for flow imbalance, and the lateral depth could be chosen at the maximum temperature practical for the available zonal isolation technology. The second well would be drilled after the stimulation of the first and could be located to either side of the first well, or even above or below (this could be selected from microseismicity observations). If proppant was used, it may be advantageous to drill the second well below the first well because proppant may tend to settle downward.
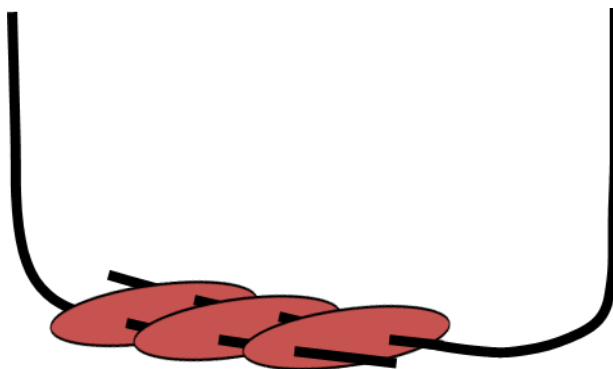
Figure 2: An EGS doublet of horizontal wells connected by vertical fracture stages (normal or strike-slip faulting regime). The wells are oriented toe to heel in order to encourage equal flow rates between stages.

1.3 Adoption of new EGS designs

Technological barriers are not the only factors preventing EGS projects from using horizontal (or deviated) wells, multiple stages, and proppant. It is widely believed that induced slip on preexisting fractures is crucial to EGS stimulation. Therefore, EGS wells are completed openhole to maximize contact between the wellbore and natural fractures. However, openhole packers are difficult to design because wellbore walls are not smooth and because wellbores often have breakouts that make their shape non-circular and unpredictable (for example, Valley and Evans, 2009). Cased hole packers are designed to seal within steel casing and are much easier to engineer and more reliable. Cased hole packers rated to geothermal temperatures are available with current technology (Section 4.3). Openhole packers may be possible at high temperature, but the technology carries greater technical risk. Overall, it would be much easier technically to perform multiple stage fracture treatments in a wellbore that has been set with casing and cemented.

Perforating wells in granite at high temperature is not typical, and this may also be an area where research is needed, but at least one service company has developed a tool rated to 230°C or higher (Barker, 2013).

In hard formations such as granite, it is unclear how easily new fractures could be initiated through perforations. Field experience injecting into openhole sections in granite indicates that during injection at bottomhole fluid pressure above the minimum principal stress, injection can often open existing natural fractures (even if not oriented perpendicular to the minimum principal stress) rather than initiate new fractures (Baumgärtner and Zoback, 1989; Cornet and Desroches, 1990; page 74 from Brown et al., 2012).

We do not believe that it is necessary to use openhole completions in order to maximize contact with natural fractures. It has recently been argued that new fractures have formed and propagated through the formation at many EGS projects (McClure, 2012; McClure and Horne, 2013a,b; Jung, 2013). Whether or not new fractures typically form at EGS projects, new hydraulic fractures would likely form during injection into a perforated wellbore section because the wellbore would have poor connection to the existing natural fractures. These new fractures may themselves create the desired EGS fracture system or they may connect the wellbore to existing fractures. After stimulation of the injector well through perforations, the producer well could be drilled through the microseismic cloud created by stimulation and completed openhole (to maximize connectivity between the newly stimulated fractures and the wellbore).

There appears to be skepticism in the EGS community about using proppants. One argument is that proppants will chemically degrade in the highly reactive environment of an EGS reservoir. Another argument is that proppants are unnecessary because fractures in granite are "self-propping" and have high transmissivity even when not propped.

There is little laboratory data directly studying the transmissivity of propped and unpropped fractures in granite. However, Stoddard et al. (2012) performed laboratory flow tests for propped and unpropped fractures in granite and found that the propped fracture retained significantly greater transmissivity at higher temperature (90°C) and normal stress (3000 psia). In Section 4.4, we review the field experience with proppant from EGS in granite and find that proppants have consistently led to improved productivity. In Section 4.5, we discuss potential issues associated with chemical degradation and possible mitigation.

A third potential concern about proppant is that it may lead to the formation of thermal short-circuit pathways. Proponents have touted an "advantage" of shear stimulation (induced slip on preexisting fractures, relying on the transmissivity of unpropped fractures to create stimulation) is that it generates distributed fracture networks, which should reduce short-circuiting by distributing flow into a more volumetric fracture network. But these pathways have generally been shown to have poor, unpredictable connectivity and inadequate overall permeability. Furthermore, it seems counterintuitive that we should avoid using proppants because they could create short-circuit pathways. Short-circuit pathways are high transmissivity pathways for flow, and inadequate flow rate is the principal obstacle preventing widespread adoption of EGS. To combat short circuiting, multiple stages could be used. Multiple stages would inhibit short circuiting because it would force fractures to form at each stage. This would distribute stimulation broadly across the entire reservoir interval. With multiple stages, a more viscous fluid could be used during stimulation, which would help transport the proppant and would tend to inhibit fracture network complexity (Cipolla et al., 2008). Network complexity implies a more volumetric fracture network. This may be viewed as good for delaying thermal breakthrough, but it may create tortuous pathways that contain bottlenecks and inhibit high circulation rates. Flow from perforated intervals might actually inhibit short-circuiting because pressure drop at the perforations would prevent extremely large flow rates from a single zone. Finally, wellbore interventions to plug short circuit intervals would be technically easier in cased, cemented completions.

1.4 Technology development strategy

In order to enable very large scale production of geothermal energy, EGS needs to be economically viable in very deep (~5 km) wells, often drilled in hard rock such as granite. However, while not as abundant, significant opportunities exist in lower cost areas, where high temperatures are available at shallower depths and formations that are easier to drill (for example, Chabora et al., 2013). Projects in granite have unique challenges because: (1) drilling is more challenging, (2) fracture initiation is more difficult, and (3) fracturing processes apparently behave differently in granite than in other types of rock.

Projects in less challenging formations could be used to prove the viability of the basic ideas proposed in this paper: (1) multiple stage hydraulic fracturing out of a cased, cemented hole, and (2) hydraulic fracturing with the intention of creating new fractures and using proppant. In early projects, direct experiments could be performed -- some stages using proppant, other stages not using proppant. Long term circulation tests could compare the ability of the stages with and without proppant to sustain permeability over time.

Ideally, early projects would be located at existing geothermal fields, on the fringes where temperature is hot but there is minimal natural permeability. These projects would benefit from the existing infrastructure and formation characterization. Low natural permeability would be advantageous because elevated natural permeability could increase fluid loss to the formation. Formations with elevated permeability are more likely to have large, well-developed faults (because large faults tend to be conduits for flow). Large faults could be induced to slip, which could deform the wellbore if intersecting the fault (Evans et al., 2005). Wellbore deformation due to a shearing fault would be a more significant problem for a cased, cemented hole than for a well completed openhole. Induced seismicity has been an issue at some EGS projects (Majer et al., 2007). An EGS project at an existing field would have the advantage that the induced seismicity hazard in the area has already been well-characterized.

2. METHODOLOGY

We conducted a sensitivity analysis to investigate the effect of multiple stages and proppant on the performance of an EGS doublet circulating fluid between two horizontal wells. The fluid circulation rate through the doublet was calculated using different assumptions about (1) the transmissivity of the fracture network created at each fracture stage and (2) the number of fracture stages. The flow rates were then converted to electricity generation rates, and the net present value (NPV) of the project revenue (neglecting cost) was calculated assuming that the production rate and temperature would be constant for 20 years. Many simplifying assumptions were made in the calculations. The calculations are intended to be used for sensitivity analysis and to demonstrate, roughly, the sort of performance than could be achieved in the system that we propose.

The baseline circulation case (one fracturing stage) was set up to be roughly equivalent to the 2005 circulation test at the EGS project at Soultz, France between GPK2 and GPK3 (Tischner et al., 2006).

2.1 Flow rate calculation

The calculations included pressure gradient in the injection well, the reservoir, and the production well. The injector and producer geometries were assumed to be the same as GPK3 and GPK2 down to the producing depth. At the producing depth, the wells were assumed to be horizontal and oriented toe-to-heel, as shown in Figure 2. For simplicity, the temperatures in the injector well, production well, and the reservoir were assumed to be constant (but different in each of the three).

The wellhead pressure of the injector, WHP_{inj}, and the wellhead pressure of the producer, WHP_{prod} were specified to be 4 MPa and 0.75 MPa, respectively (following the Soultz circulation test described by Tischner et al, 2006). Flow was also driven by the difference in density between the fluid in the injection well and the production well. Flow rate could have been increased by using a higher injection pressure, but excessively high injection pressure may lead to excessive fluid loss. Flow rate could have been increased by pumping the production well, but this would involve additional cost and parasitic power loss. In practice, it would probably be economic to pump the production well, and it may be feasible to use a higher injection pressure than we assumed, but we chose these values in order to give conservative estimates.

To simplify the calculation, it was assumed that all fluid entered or exited the wellbores at the bottom of each well at a single location (even though we were modeling wells with multiple stages). The system was modeled as four nodes connected in series: $WHP_{inj}, BHP_{inj}, BHP_{prod}$, and WHP_{prod}, where BHP_{inj} and BHP_{prod} are the bottomhole pressure of the injector and the producer wells, respectively. Wellbore pressure drop calculations were used to calculate ΔP_{inj}, equal to $WHP_{inj} - BHP_{inj}$, and ΔP_{prod}, equal to $WHP_{prod} - BHP_{prod}$ (as described in Section 2.1.1). Darcy's law was used to calculate ΔP_{res}, equal to $BHP_{inj} - BHP_{prod}$ (as described in Section 2.1.2). All fluid in the system was assumed to be single phase, liquid water.

For a given value of reservoir transmissivity, the flow rate through the system was calculated by numerically solving the following nonlinear equation, with flow rate, q, as the unknown:

$$WHP_{prod} = WHP_{inj} + \Delta P_{inj}(q) + \Delta P_{res}(q) + \Delta P_{prod}(q),\qquad(1)$$

2.1.1 Pressure change calculation in the injection well and the production well

This section explains how $\Delta P_{inj}(q)$ and $\Delta P_{inj}(q)$ were calculated. The total pressure gradient (dp/dz) can be calculated as the sum of the frictional gradient $(dp/dz)_F$, the hydrostatic gradient $(dp/dz)_H$, and the accelerational gradient $(dp/dz)_A$ (Hasan and Kabir, 2002) and is given by:

$$(dp/dz) = (dp/dz)_F + (dp/dz)_H + (dp/dz)_A.\qquad(2)$$

From the conservation of momentum, the hydrostatic and the accelerational gradients are represented by:

$$(dp / dz)_H = -g \rho \sin \theta , \tag{3}$$

$$(dp / dz)_A = -(w / A)dv / dz = -\rho v dv / dz , \tag{4}$$

where ρ is the density of fluid, θ is the wellbore angle from horizontal line, w is the fluid mass of flow rate, A is cross-sectional area of casing, and v is its velocity.

The frictional pressure gradient is:

$$(dp / dz)_F = -fv^2 \rho / 2d , \tag{5}$$

where d is well or pipe diameter and f is friction factor, which depends on the turbulence of the fluid and also on the pipe roughness.

Chen (1979) proposed the following equation to calculate the Fanning friction factor:

$$f = \frac{1}{\left[2 \log(\frac{\varepsilon / d}{3.7065} - \frac{5.0452}{Re} \log \Lambda) \right]^2} , \tag{6}$$

where ε is pipe roughness, and Λ is the dimensionless parameter given by:

$$\Lambda = \frac{(\varepsilon / d)^{1.1098}}{2.8257} + \left(\frac{7.149}{Re} \right)^{0.8981} . \tag{7}$$

Fluid properties were chosen for fresh water and are given in Table 1. The temperature in the injection well was assumed to be 60°C, and the temperature in the production well was assumed to be 180°C. The surface roughness of casing was assumed to be 150 microns, as estimated for the wellbore casing of GPK2 at Soultz by Mégel et al. (2005) based on measurements of the wellhead and bottomhole pressure during injection.

Table 1: Properties used in the flow rate calculations. The reservoir transmissivity shown is the "baseline" transmissivity.

Properties	Injector	Reservoir	Producer
Temperature (°C)	60	190	180
Fluid density (kg/m³)	983.2	873.9	885.0
Fluid viscosity (cp)	0.466	0.142	0.151
Transmissivity (m³)		3.07E-13	

Table 2 shows the geometry of the injection and production wells (based on the Soultz wells GPK2 and GPK3) including depth, casing diameter and inclination (Tischner et al., 2006). Table 2 contains the extended laterals on the horizontal wells (which were not present in GPK2 and GPK3). The wellbore lengths increased by 150 m for every stage that was added. The extended horizontal part of the injection well was assumed to be completed with casing and perforations (cased hole completion). The horizontal lateral of the production well was assumed to be openhole. The roughness of the formation in the openhole was assumed to be 2000 microns. Pressure drop in the perforations was not included in the calculation.

Considering the flow geometry shown in Figure 2, each molecule of water will pass through the same length of wellbore as it passes through the system (regardless of which stage it flowed through the reservoir), and that length is equal to half of the total length of both the laterals. To account for this effect, every time a stage was added, the length of the horizontal lateral in both the injector and the producer was increased by one half the spacing between stages, 75 m.

Table 2: Geometry and well head pressures of the injection well and production well.

Wellbore	MD (m)	Pipe diameter (in)	Wellbore angle from horizontal (°)	WHP (MPa)
Injector	0-2373		83.7	
	2373-3449		70.9	
	3449-4282		70.9	
	4282-4550		90	
	4550-4610	9 3/8	75.0	
Injector possible extention (Cased hole)	4610 - [4760-6110]	9 3/8	0	4
Producer	0-534	13 5/8		
	534-4084		90	
	4048-4638	7	79.2	
Producer possible extention (Open hole)	4638 - [4788-6138]	8 1/2	0	0.75

2.1.2 Pressure change calculation in the reservoir

This section explains how $\Delta P_{res}(q)$ was calculated. The pressure change through the reservoir was calculated from Darcy's law, assuming steady-state, linear flow through a fracture with height h (m) and transmissivity T (m^3):

$$\Delta P_{res} = \frac{q \mu D}{T h \rho} \tag{8}$$

where ΔP_{res} is BHP_{inj} - BHP_{prod} (MPa), q is flow rate of the reservoir (kg/s), μ is the viscosity of fluid (cp, or for unit consistency in Equation 8, MPa-s), and D is the distance between the injector and producer (m).

The Soultz project was used to make a baseline estimate for the transmissivity of an EGS reservoir. During the 2005 circulation test at Soultz, a 12 kg/s flow rate was sustained between GPK2 and GPK3. The openhole section of the wells was roughly 500 m and the well separation was roughly 600 m. Using those parameters, and using the reservoir and wellbore properties given in Tables 1 and 2 (which were based on the Soultz circulation test), the reservoir transmissivity was estimated to be 3.07×10^{-13} m^3. We used this value as our baseline transmissivity for a single stage.

The exact nature and geometry of the fracture network at Soultz (or the network created in our hypothetical EGS system) is not important for the calculation. We are using a single number, reservoir transmissivity, to account for the aggregate flow capacity of the created fracture network, whether it was a single, planar hydraulic fracture, a dense network of stimulated natural fracture, a large, thick, shear stimulated fault zone, or network of both new and preexisting fractures.

In our hypothetical EGS doublet, we assumed D and h to be 200 m. The wellbore spacing is a design parameter. A spacing of 200 m would be too small for a single stage (due to thermal breakthrough) but with enough stages, a smaller spacing could be acceptable. In future work we will perform a more complicated analysis including thermal breakthrough.

When there were multiple stages, we assumed that flow was evenly distributed between each stage. Therefore, the flow rate per stage was q/S, where S is the number of stages. In Equation 8, this was implemented by making the total system transmissivity equal to TS. Table 1 shows the fluid properties used in the calculations.

2.2 Sensitivity analysis (effect of stages and proppants)

Plots were made of total flow rate versus number of stages. Aside from the baseline transmissivity, T (equal to 3.07×10^{-13} m^3), we performed calculations for other values of reservoir transmissivity, *T/4, 2T, 4T,* and *5T*. The lower value of transmissivity was included to show the consequences of an inadequate stimulation. The higher values of transmissivity were included to show what could be possible if stimulation technique could be improved (whether through the use of proppant or some other technique). As discussed in Sections 1.3 and 4.4, proppant use may significantly increase the transmissivity of flow paths created in EGS reservoirs. The Soultz wells, which we used to establish our baseline transmissivity, were not stimulated with proppant.

2.3 Conversion to electricity

The rate of thermal energy production at the power plant was calculated with the following equation:

$$Q = q C_p \Delta T , \tag{9}$$

where Q is the rate of thermal energy production (J/s), q is mass flow rate (kg/s), C_p is specific heat capacity of fluid (J/kg/K), and ΔT is difference of temperature (K) across the system.

Since we assumed that the temperatures of the injection and production wells were 60°C and 180°C, respectively, the difference of temperature was 120°C. A heat capacity of 4.42 J/g/K was assumed. We assumed that the efficiency of conversion from thermal energy to electricity to be 12.63% (from Equation 7.1 from Tester, 2007) and the price of electricity to be either 5 or 10 cents per kWh.

2.4 Net present value (NPV) of electricity

We calculated the net present value (NPV) of the revenue from the project. Net present value is defined as:

$$NPV(i, N) = \sum_{t=0}^{N} \frac{R_t}{(1 + i)^t} ,$$

(10)

where i is the discount rate, t is the time of the cash flow (years), R_t is the net cash flow ($), N is the total number of periods.

We assumed the discount rate to be 16% (Hochwimmer et al., 2013) and that production could be sustained at constant temperature for 20 years.

3. RESULTS

3.1 Flow rate

Figure 3 shows flow rate and number of stages for each transmissivity. The transmissivity T is the baseline transmissivity (3.07 × 10^{-13} m^3). Calculations were performed for each of the five transmissivity values for one to ten stages.
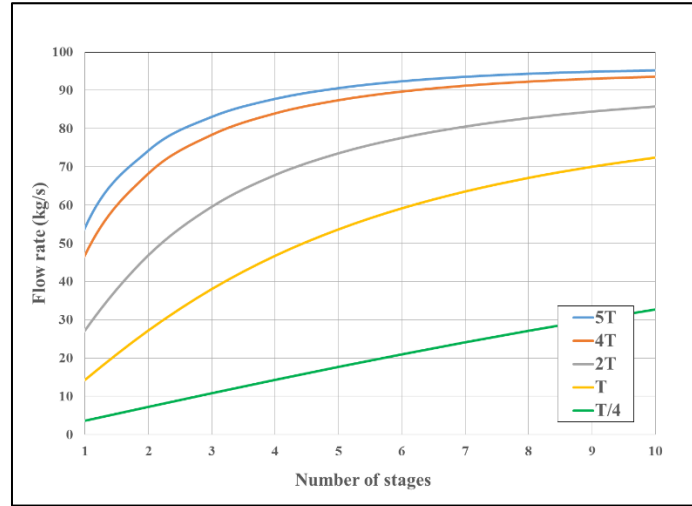

Figure 3: Flow rate versus the number of stages

3.2 Pressure drop

Figure 4 shows two lines for each calculation. The solid lines give the sum of the frictional and accelerational pressure drop in the injector and producer. The dashed lines give the pressure drop in the reservoir, BHP_{inj} - BHP_{prod}.
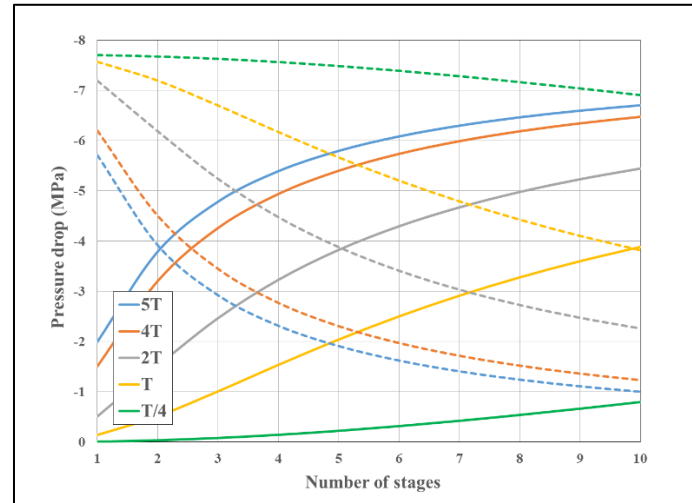

Figure 4: Pressure drop versus the number of stages. The solid lines represent the sum of the frictional and accelerational pressure drops in the injector and producer. The dashed lines represent the pressure drop in the reservoir.

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3.3 Power and NPV

Figure 5 shows the calculated electricity generation for each case. Because flow rate is linearly related to power generation, the shape of curve is identical to Figure 3.
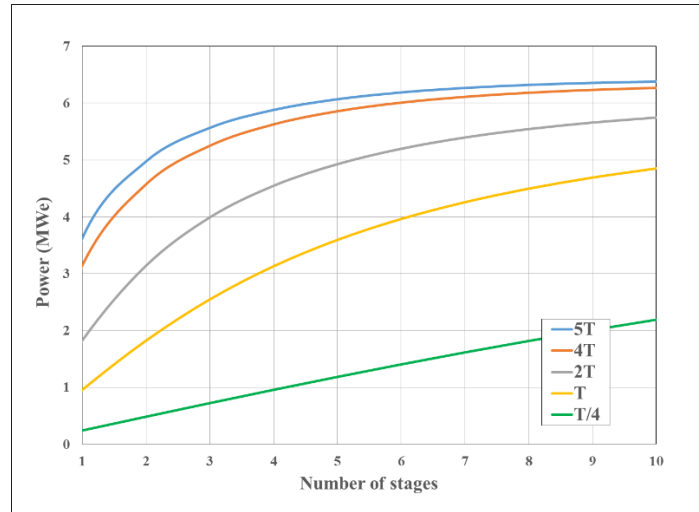

Figure 5: Power (electricity) versus the number of stages

Figures 6 and 7 show the NPV of the project revenue (neglecting cost) for electricity prices of 0.05 $/kWhr and 0.10 $/kWhr.
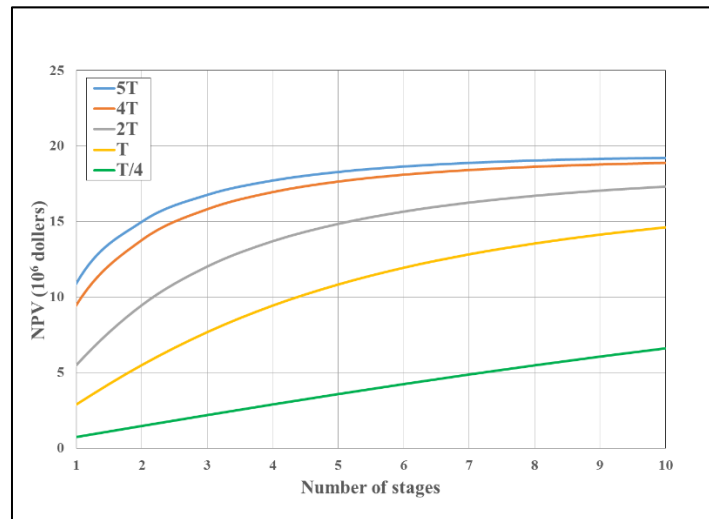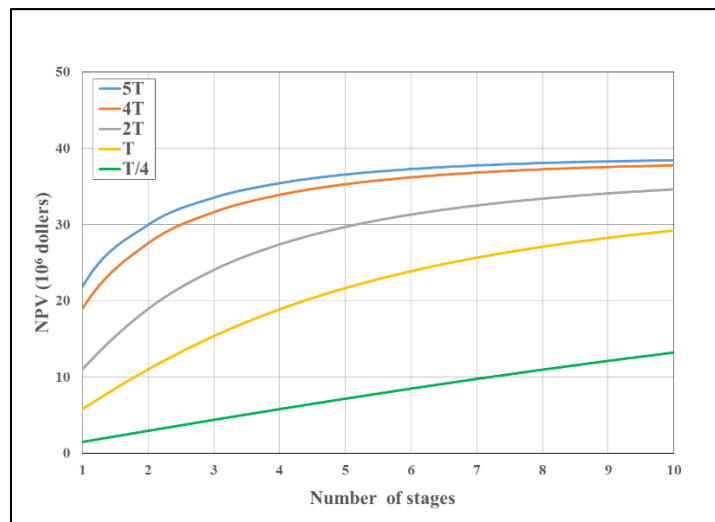

Fig 6: NPV versus the number of stages at 0.05 $/kWh

Fig 7: NPV versus the number of stages at 0.10 $/kWh

4. DISCUSSION

4.1 Increasing the number of stages

From Figure 3, it can be seen that flow rate initially increases linearly as the number of stages increases. However, the flow rate begins to plateau at high rates, which is due to the pressure drop in the wellbore, which increases nonlinearly. The frictional pressure drop increases with the square of the flow rate (Equation 5). The pressure drop in the wellbores also increases as the number of stages increases because the horizontal sections of the wells are becoming longer. As the reservoir transmissivity gets bigger (due to increasing number of stages or increasing transmissivity per stage), the proportion of the overall pressure drop that occurs in the reservoir drops (Figure 4). The overall hydraulic head difference during flow through the system is constant, and equal to the difference in the wellhead pressure of the injector and the producer plus the difference in hydrostatic head caused by the temperature (and density) differences of the fluid in the injector and producer.

4.2 Increasing the transmissivity of each stage

Five different values were used for transmissivity per stage. As seen from Figure 3, the number of stages until flow rate became mostly constant depended on the transmissivity. For larger transmissivity, flow rate reached a constant value with fewer stages and vice versa.

In this study, we assumed that the stages were identical and did not affect each other. However, in the real life, it is possible that fractures from one stage could intersect fractures from another stage. This might decrease the overall transmissivity per stage, an effect that we did not include.

4.3 Current technologies for high temperature zonal isolation

Performing a multiple stage fracture treatment requires the ability to hydraulically isolate sections of the wellbore to pump into each stage sequentially. This requires the use of packers or bridge plugs. In this section we provide a nonexhaustive review of technologies available from the service industry.

Cased hole packers and bridge plugs rated to temperatures and pressure typical for EGS projects are available from oilfield service companies and have been demonstrated in the field. Packers Plus has developed packers rated to 300°C and 69 MPa. These packers have been installed successfully at the Cooper Basin EGS project and in high temperature high pressure oil and gas wells (Rivenbark et al., 2011; Rivenbark and Lefsrud, 2013; Packers Plus, 2013). Schlumberger's Copperhead drillable bridge and flow through frac plugs are rated to 204°C and 103 MPa (Schlumberger, 2012). Baker Hughes has developed a cased hole packer rated to 232°C and 138 MPa (Doane et al., 2013). Halliburton developed a packer rated to 232°C and 103 MPa, designed to work even worn casing (Innes et al., 2010). Interwell has a high pressure high temperature retrievable bridge plug rated to 200°C and 103 MPa (Interwell, 2011).

Bendall et al. (2014) reviewed several recent EGS projects in Australia. They reported that operators with Petratherm's Paralana project successfully performed a large hydraulic stimulation in granite through perforated casing and with cased hole packers at temperature of nearly 190°C.

Drillable plugs set in cased, perforated hole were used successfully to enable multiple fracture stages in the well GtGrSk4/05 at Groß Shönebeck at 150°C in sandstone and volcanic formations (Zimmermann et al., 2010). The bridge plugs were provided by Weatherford and were rated to 177°C and 69 MPa (Günter Zimmermann, personal communication).

Openhole packer technology at high temperature appears to be significantly more limited. A Baker Hughes tool is rated to 316°C but is limited to in or near gauge wellbore. Another Baker Hughes tool is rated to 170°C (Walters et al., 2012). Walters et al. (2012) reports that an openhole packer system developed by Packers Plus and marketed by Schlumberger is rated to 199°C.

Additional review of zonal isolation at high temperatures was given by Walters et al. (2012).

4.4 EGS field experience with proppant

Proppant has been used at a limited number of EGS projects in granite. In every case, proppant has been placed successfully and increased fracture transmissivity.

The earliest experiment was a small test at the Fenton Hill project in 1974 (page 74 from Brown et al., 2012) involving injection into an openhole section isolated with packers. In the first test, injection was performed, and there was limited fluid recovery during subsequent flowback. Fluid was believed to be entering a natural fracture that was opening in response to injection. Injection was repeated with proppant, and almost full recovery was achieved. The implication is that without proppant, the natural fracture at the wellbore closed during flowback and hydraulically isolated the remaining injection fluid away from the wellbore. With proppant, the fracture retained transmissivity when it closed during flowback, enabling nearly full recovery. Evidently, the natural fracture had much greater transmissivity (post-closure) when filled with proppant.

The first large experiment with proppant at an EGS project was in the well RH15 at Rosemanowes (Bennett et al., 1989). Proppant was injected with viscous gel at high rate into an openhole section roughly 150 m long. Production logs showed that after stimulation, the main conduit for flow at the well was a single fracture, believed to be where the injected proppant had gone (Bennett et al., 1989). Parker et al. (1999) reported that the proppant placement resulted in a significant lowering of system impedance and water loss during circulation. The proppant was so effective at improving connectivity that it was blamed for worsening a thermal short-circuit.

Cornet and Desroches (1990) described a series of stimulations in the wellbore INAG III-9 at Le Mayet. Injections were performed into four openhole sections isolated with packers. In the upper section, resistivity logs indicated an altered zone, and spinner logs prior to stimulation indicated a flow conduit. The other three zones each contained a fracture identified in a wellbore imaging log

but were not flowing. The upper three zones were stimulated with viscous gel at around 70 cp. The lowest zone was stimulated with both viscous gel and proppant. After stimulation, spinner logs indicated flowing zones at the upper zone (where a flow conduit had previously existed) and the lower zone (where proppant was used). There was no flow from the wellbore at the middle zones (where only gel was used). Subsequently, high rate and pressure injection (above the minimum principal stress) was performed in the entire well interval, and spinner logs indicated that the middle sections were major outflow zones. This indicates that during the high pressure injection, natural fractures at the middle zones opened and were highly transmissive. But when bottomhole pressure was lower, the middle fractures closed and had low transmissivity. At lower pressure, only the propped zone and the preexisting flow zone retained transmissivity. The results suggest that proppant had the effect of significantly improving fracture transmissivity.

The well EGS GtGrSk4/05 at Groβ Shönebeck was stimulated in sandstone and volcanic rock with proppant (Zimmermann et al., 2010). The stimulation was very successful and resulted in a large increase in well injectivity.

Proppant was used at the Fjällbacka project (Wallroth et al., 1999), but we were unable to find additional details.

4.5 Chemical stability of proppant at high temperatures

Some studies of proppant chemical stability under geothermal conditions have indicated dissolution could be a concern. Brinton et al. (2011) conducted batch experiments on proppant (sand and bauxite) dissolution at 200°C over periods of several months. Evidence was found that dissolution occurred, but dissolution was not directly related to changes in proppant strength or transmissivity. Deon et al. (2013) performed batch experiments with corundum proppants at 150°C for up to 80 days, and found evidence that dissolution occurred. They also did not investigate how the dissolution affected proppant permeability or strength. They found that resin coating did not affect the tendency for dissolution.

Raysoni and Weaver (2013) performed batch experiments with aluminum-based proppant at up to 450°F for 60 days or more. They tested the retained strength and permeability of the proppant materials before and after treatment. They found significant loss of strength and permeability in uncoated proppants, but slight or nonexistant loss or strength and permeability in proppants that were coated with hydrophobic surface-modification agents. These results are not necessarily inconsistent with the results of Deon et al. (2013) because it is likely that a different proppant coating was used.

In reality, it is impossible to replicate field conditions in the laboratory. The laboratory results suggest dissolution may be a concern, but the degree to which it may reduce fracture transmissivity is not really known. The only way to truly test proppant performance would be with long-term circulation tests in an actual EGS reservoir. Proppant material (and coating) could be selected on the basis of laboratory batch experiments using site-specific fluid samples, rock types, and temperatures. Even with degradation, proppant may still be able to increase system performance. In practice, if reservoir transmissivity was found to degrade over time (and it was suspected that proppant degradation was responsible), wells could be refractured with additional proppant. Refracturing may be cost effective because drilling and surface facilities are the dominant drivers of cost for EGS, not stimulation cost (Sanyal et al., 2007).

5. CONCLUSION

Our simple calculations demonstrate that using multiple stages in an EGS well could result in substantially higher flow rates, electricity production, and revenue generation. Multiple stage completions have not generally been used in EGS because of the technical challenge of using openhole packers. We believe that cased hole completions could be effective (for the well that is stimulated, not the production well drilled subsequently). Cased hole zonal isolation at high temperature is possible with current technology. Not only would the use of multiple stages allow higher flow rates, it would inhibit thermal short-circuiting by distributing flow over a larger number of fractures.

The ideal wellbore geometry for an EGS doublet would be two horizontal wells, oriented toe-to-heel. Horizontal drilling is technically feasible at temperatures seen in most EGS projects, but we are uncertain about the incremental cost, especially in the hard rock formations where EGS is often attempted. As an alternative to horizontal well completion, deviated wells could be used, or vertical wells in a reverse faulting regime.

Our review of the literature shows that in the few cases where proppant has been used in EGS projects in granite, it has clearly improved fracture transmissivity. Laboratory investigations of proppant dissolution at high temperature are inconclusive, but at least one study indicated that coated proppants are resistant to degradation.

Deviated or horizontal EGS wells with cemented, cased production intervals, multiple stage fracturing treatments, and proppant would have higher completion and drilling cost. But much of the cost of an EGS project is from drilling to the target depth, building surface facilities, and long term operation. These technologies could increase project revenue by several multiples.

There are technical challenges in applying these technologies, but they offer a clear path forward for designing EGS projects with radically improved economic performance.

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