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Hydraulic Well Stimulation in Low-Temperature Geothermal Areas for Direct Use

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ABSTRACT

Direct use of hot water through renewable energy resources is globally in demand. Thermal energy stored in fractures and pores within geothermal reservoirs contains natural fluids. At times, extracting natural fluids, or hot water in low-temperature areas, can be a challenge. Hydraulic stimulation is one technique to overcome this challenge. A review of hydraulic stimulation methods is provided based on fluid treatment and well testing in order to see unique trends for low-temperature geothermal applications. In order to predict the effects of hydraulic stimulation before an actual operation, a case study was performed on well HF-1 in Hoffell, Iceland. First, a preliminary lumped parameter model (LPM) was performed using the updated data from completion of testing in 2014. After evaluating the need for stimulation, a fracture model using MFrac software was done in two scenarios with an open-hole packer - injection below the packer and injection above the packer. The packer was placed in a conservative interval of 1070-1110 m depth to isolate the main fracture at 1093 m depth. Injection below the packer failed, therefore results from injection above the packer were only suitable moving forward. Subsequently, MProd software was used to find a production improvement ratio after simulating stimulation above the packer. The improvement ratio of 1.096 was then applied to the original production data of well HF-1 and a LPM was performed yet again. Reservoir properties of storativity (*S*), transmissivity (*T*), injectivity index (*II*), and productivity index (*PI*) were calculated and compared to original production data. Results indicated the lumpfit model to be very optimistic for the two-tank open scenario and improvement of only 4 l/s flow over a 10 year well lifetime was observed. Therefore, the well is not a good candidate for stimulation. However, the presence of an improvement ratio proves the potential for this methodology to be implemented in other low-temperature geothermal areas.

1. INTRODUCTION

Direct use of geothermal energy is traditionally applied on a small scale for individual use, but more recent developments involve large scale projects in commercial industry. Direct application of geothermal energy involves a wide variety of end uses, such as space heating and cooling, greenhouses, fish farming, and health spas. Flexibility in direct application by use of geothermal energy makes a more attractive option over other means of resource exploitation; such as coal, oil, gas, or electricity.

Thermal energy, or hot water, in the earth's crust is distributed between constituent host rock and natural fluids that are contained in fractures and pores at temperatures above some specified reference temperature (Tester, et al. 2005). Extraction of hot water can sometimes present several challenges due to possible obstructions in fractures or poor fracture connectivity to the reservoir. Hydraulic stimulation is one technique to overcome challenges of fluid extraction.

Low-temperature geothermal fields (<150˚C) by nature compose of resources used almost entirely for purposes of hot water production for direct use. Hydraulic stimulation in low-temperature geothermal areas for direct use creates more potential to access natural fluids. Stimulation procedures provide for a better way to make an almost exclusive network to meet local demand. The knowledge gap lies in predicting the amount of production potential from natural fluids after a hydraulic stimulation operation.

2. BACKGROUND

2.1 Frac Fluid Treatment

There are mainly three types of proppant injection fluid methods used during hydraulic stimulation within a pay zone. A pay zone is the portion of rock in a reservoir that contains economically producible hydrocarbons, or hot water in geothermal applications (Vollmar, Wittig and Bracke 2013).

Hydraulic Proppant Fracturing (HPF) is the most conventional method in use for hydraulic stimulation (Aqui and Zarrouk 2011). HPF uses highly viscous gel as fracturing fluid, usually in the form of a polymer. A high proppant concentration creates conductive yet relatively short fractures in porous media suitable in reducing permeability impairments (i.e. "skin") in the wellbore, as illustrated in Figure 1. The well is shut after the fracturing process to allow proppant transport through the fractures. However, HPF is prone to leave gel residues and may result in the precipitation of minerals, which affects well performance (Aqui and Zarrouk 2011).

Water Fracturing (WF), or "Water Fracs", is essentially water containing friction-reducing agents added with a low proppant concentration. The WF method creates long and narrow fractures from the wellbore to the natural fracture network, which is at some distance from the main reservoir, as illustrated in Figure 2. The fracture conductivity induced by WF is maintained by the self-propping ability of the reservoir rock. Since WF is dependent on the self-propping ability of the reservoir formation, fracture closure is likely to occur rapidly as a result of pressure solution processes in regions of high stress (Aqui and Zarrouk 2011). In addition, the low viscosity of water makes it difficult to effectively transport proppants into the newly created hydraulic fractures (Aqui and Zarrouk 2011).

Hybrid Fracturing (HF), or "Hybrid Fracs", is a combination of different gels used in the HPF method and slick water fluids used in the WF method, or otherwise known as a cross-linked gel proppant. The concept is to utilize the advantages of the HPF and WF methods in creating the fracture geometry as well as effectively placing the proppant into the induced fracture. In the HF method, the fractures are considerably longer compared to HPF and the effective propped fracture length is higher compared to WF (Reinicke, et al. 2010).

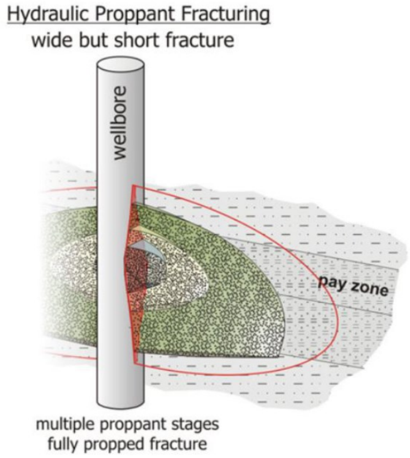


Figure 1: Fracture propagation as a result of Hydraulic Proppant Fracturing (Reinicke, et al. 2010).

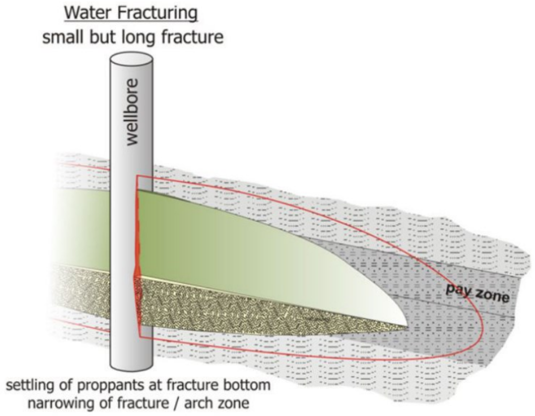


Figure 2: Fracture propagation as a result of Water Fracturing (Reinicke, et al. 2010).

2.2 Hydraulic Well Testing

Well testing is performed to compare well behavior before and after a stimulation, and is typically used as a point of reference during stimulation between cycles. When a well is subjected to injection in order to monitor the pressure response in a reservoir (i.e. pressure transient), it is used to evaluate the properties that govern flow characteristics in the well. The properties discussed here are storativity and transmissivity.

The storativity describes pressure movement within the reservoir, and is defined as:

$$S = c_t h \tag{1}$$

where S, c_t, and h are storativity [$m^3/Pa \bullet m^2$], compressibility of the fluid [Pa^{-1}], and effective reservoir thickness [m], respectively.

The transmissivity describes the ability of the reservoir to transmit fluid, which mainly effects the pressure gradient between the well and the reservoir, and is defined as:

$$T = \frac{kh}{\mu} \tag{2}$$

where T, k, h, and μ are transmissivity [m^3/Pa•s], permeability of the rock [m^2], effective reservoir thickness [m], and dynamic viscosity of the fluid [Pa•s], respectively.

During an injection test, the injectivity index is often used as an estimate of the connectivity of the well to the surrounding reservoir and is defined as:

$$II = \frac{\Delta Q}{\Delta P} \tag{3}$$

where II, ΔQ, and ΔP are injectivity index [(L/s)/bar], change in flow rate [L/s], and change in pressure [bar], respectively.

In the case of low-temperature wells tested through production step testing a comparable index is defined, termed productivity index (PI). The productivity index is a measure of well potential, or ability to produce, and is defined as the total mass flow rate per unit pressure drawdown.

2.3 Types of Hydraulic Stimulation

The methods of hydraulic stimulation are classified into three categories, as applied on geothermal wells. Air-lift aided drilling (also referred to as pressure balanced drilling, under-balanced drilling (UBD), or aerated drilling) has proven to be successful in preventing the clogging up of feed zones during drilling, but is not necessarily considered a stimulation operation per se (Axelsson, Thorhallsson and Bjornsson 2006). The water circulation phase after air-lift aided drilling could be classified as an open-hole stimulation via injection at the wellhead, and is performed in a similar matter.

Another method of stimulation is the isolation of intervals in the borehole through the use of a packer, in particular to an open hole section. After the packer is set, water may be injected either below the packer, through the drill pipe, or into the annulus above the packer (Tomasson and Thorsteinsson 1975). Double packers are also considered to be a method of hydraulic stimulation, but have hardly been used in geothermal stimulation operations; even though they are potentially more powerful than a single packer due to injected water being focused within a shorter interval (Axelsson, Thorhallsson and Bjornsson 2006).

Lastly, zonal isolation is a method used to target one fracture at a time within the wellbore. Several options are available to achieve zonal isolation, where each technique must be integrated into drilling and well construction (Walters, Thorhallsson and Wood 2012). A simple approach is to use a liner made out of cement or sand that is perforated to distribute fluid across the reservoir. Another approach is to add an inflatable or swellable packer, creating a seal to isolate the desired stimulation interval. The plug and go method involves drilling until a fracture is reached, stimulating the fracture, and then isolating the interval to be repeated over the entire depth of the wellbore. Finally, the use of multilateral wellbores and sidetracks involves first drilling a pilot hole, then drilling either multiple holes to intersect individual fractures or drilling a deviation hole to more accurately target the upper fractures of the reservoir.

3. LITERATURE REVIEW

3.1 Low-temperature Geothermal Areas

Hydraulic stimulation by use of open-hole packers and large flow of water has had success in low temperature geothermal areas, specifically in Iceland starting in the early 1970s. The Reykir hydrothermal system was an ambitious stimulation program, when each of the 39 wells drilled during redevelopment of the field were stimulated after drilling. Seltjarnarnes well SN-12 was drilled in 1994, where the decision to stimulate the well resulted from a measured flow yielding almost no production after drilling (Tulinius, et al. 1996).

3.1.1 Reykir Hydrothermal System

The Reykir hydrothermal system has been exploited since 1944 for space heating of Reykjavik, Iceland. Prior to 1970, production amounted to 300 l/s at 86˚C by free flow from 69 wells (Thorsteinsson 1975). In the early 1970's, the Reykir field was redeveloped with the addition of 39 wells to be hydraulically stimulated, by injection above and below inflatable packers, as part of a drill completion program.

In general, air-lift pumping was done to clean the hole of drill cuttings and lost circulation materials. A packer was then set a certain depth, between two or more producing horizons, where water was injected beneath or above the packer. Pumping rate varied from 15 to 100 l/s for each well due to the resistance of the producing horizons. Pressure increases at the feed zones ranged from a few bars up to as high as 150 bars at the lowest permeability feed zones treated (Thorsteinsson 1975).

Four wells are examined further to compare improvement ratios after stimulation, as seen in Table 1. The total improvement ratio for wells MG-25 and MG-35 is significantly higher than that of wells MG-27 and MG-39. The drastic improvements are mostly attributed to the reopening of feed-zones clogged by drill cuttings during drilling operation (Axelsson and Thorhallsson 2009). However, when comparing production over the cumulative loss of circulation during drilling, the wells showed a 1-2 fold increase in production. This is attributed to increased feed-zone permeability, most likely due to the removal of zeolite and calcite vein deposits and partly to increased permeability of near-well fractures in hydroclastic rocks (Axelsson and Thorhallsson 2009). Fluid losses tend to be higher for wells with a high initial total improvement ratio at about 88 %, and fluid losses tend to be lower for wells with a low initial total improvement ratio at about 62 %. In total, more than 1500 l/s was produced for all 39 wells, which is about a 5 fold average increase for the area.

Table 1: Improvement ratios for specific wells in the Reykir Hydrothermal System (Thorsteinsson 1975).

Well No.	Total improv. ratio	Improv. ratio after circ. losses	Percent fluid loss
MG-25	14	2.2	84.3%
MG-27	2.6	1.06	59.2%
MG-35	32.9	2.7	91.8%
MG-39	3.9	1.35	65.4%

3.1.2 Seltjarnarnes Well SN-12

Prior to stimulation, the average production flow Seltjarnarnes well SN-12 was around 1.5 l/s with a drawdown of roughly 150 m (Tulinius, et al. 1996). The well was stimulated in two phases – via high pressure wellhead injection and high pressure injection below a packer. Figure 3 shows the results of each stimulation by using an air-lift test, as well as a production test conducted after the first stimulation. Comparing results from the air-lift tests indicate an increase in flow to about 35 l/s with a drawdown of roughly 60 m, indicating the stimulation had increased the yield of the well by a factor of 23. Thus well SN-12, which appeared to be almost non-productive at the completion of drilling, had turned into a good production well (Axelsson and Thorhallsson 2009).

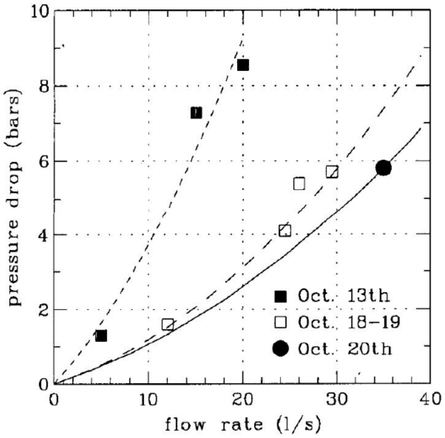


Figure 3: Results of production testing of well SN-12, where symbols show observed data one hour into each step and lines show calculated output characteristics (Tulinius, et al. 1996).

3.2 History of Stimulation Fracture Modelling

Fracture modeling is important to determine the success (or failure) of a stimulation operation and is usually performed before stimulation commences. Two known cases are pointed out in Germany and Canada for fracture modeling using FRACPRO and MShale software. FRACPRO is typically used to address the prediction of pressure response in the well for planned stimulation treatments and the selection of appropriate equipment to handle expected wellhead pressures, friction, and near wellbore tortuosity (Zimmermann, Moeck and Blocher 2010).

Well GrSk4/05 at the Groß Schönebeck EGS site in Germany was first modeled in FRACPRO, then used as a real-time simulation tool. While fracture propagation was the goal of stimulation, the main purpose of FRACPRO was to model a treatment schedule (Zimmermann, Moeck and Blocher 2010). In the Ft. McMurray area of Canada, research was performed with MShale to extract hot water from natural oil sands. A sensitivity analysis of estimating reservoir properties using prior knowledge about fracture location was done in order to determine the potential for an HDR project, and subsequently to determine optimal areas for stimulation (Hofmann, Babadagli and Zimmermann 2014). Both cases were primarily concerned with modeling the effects of stimulation on fracture geometry. However, these software do not account for any potential production flow improvements after stimulation. A number of other fracture modeling software is available, but most model seismic activity with the goal to minimize environmental impact.

Historically, the importance of fracture modeling was about the emphasis in fracturing low-permeability reservoirs in order to model the productive fracture length and the dimensionless fracture conductivity; i.e. the ratio of the ability of the fracture to carry flow divided by the ability of the formation to feed the fracture (Economides, et al. 2000). There is a need to derive a solution methodology from the oil and gas industry in order to take the effects of stimulation on fracture geometry and apply them to model production potential. This is the motivation for modeling in the MFrac suite for direct use purposes using geothermal resources.

4. METHODS

4.1 Case Study: Hoffell Well HF-1

4.1.1 Background

The Hoffell case study area is located in SE-Iceland about 15 km outside the city of Hofn (pop. 1700), as shown in Figure 4. Hoffell is a low temperature geothermal field about 400 km east of Reykjavik, the capital city of Iceland. Geothermal exploration in Hoffell began in 1992 with research done on surface geology, magnetic measurements, chemical analysis of the water, and geothermal gradient drilling. Exploration results showed that there is potential of exploitable low temperature geothermal resources, as temperature gradients of up to 186˚C/km were observed and chemical composition of the water indicated a 70-80˚C temperature deep in the water system (Hjartarson, Flóvenz and Ólafsson 2012).

Figure 4: Map showing the location of the Hoffell case study area (Masum 2014).

RARIK (Iceland State Electricity) drilled well HF-1, but before the well was drilled in 2012 there were already 33 boreholes in the area (Kristinsson, et al. 2013). The drilling of well HF-1 at Hoffell started in early November 2012 and lasted until January 11, 2013. The hole was first drilled down to 1,208 m depth, but was later deepened in February 2013, first to 1,404 m and finally to 1,608 m depth (Kristinsson, et al. 2013). Most of the exploration wells were drilled N-S as surface manifestations indicated the main fault line to be in this direction. However when well HF-1 was drilled and tested, the free flow rate was very low at about 7 l/s. Recently, data loggers placed in the exploration boreholes on the east side of the geothermal field indicated that the main fault line is most likely oriented NE-SW, which may explain the low flow of well HF-1.

After drilling was completed, long term production testing was performed to understand the reservoir behavior and to estimate its production potential (Shengtao 2014). The test started April 9, 2013. Water-level drawdown, production flow rate and temperature were monitored and recorded continuously. The test concluded 13 months later on May 9, 2014.

4.1.2 Initial Production Modelling

Lumped parameter modeling (LPM) is a simplified form of numerically modeling the hydrological properties of a low temperature geothermal reservoir. The observed changes in reservoir pressure (or water level) and the fluid production/injection rates can be matched between measured and calculated data, and consequently the fluid and/or energy production potential of a given field can be predicted. While the 13-month production test was being conducted for Hoffell well HF-1, LPM work by Shengtao (2014) was done for the first five months of production testing from April 9, 2013 to September 8, 2013. The LPM conducted here uses a Lumpfit program written by Iceland GeoSurvey (ISOR) and is based on data from the 13-month production test, but starting one month later from May 9, 2013 as data for the first month was deemed invalid. The purpose of performing a pre-stimulation production analysis with the additional production test data is to foresee a more accurate prediction of the required flow for sustaining production over a certain period of time. The calculated required flow will be used as a guideline for determining the effects of the post-stimulation treatment.

In Shengtao's analysis, two lumped parameter models, a two-tank closed model and a two-tank open model, were used to simulate the five-month production data from well HF-1. The two models were chosen as they provided a good fit between the measured and calculated water level in the well, which can be seen in Figure 5. In this analysis, only the two-tank open model was considered, as the two-tank closed model did not provide a good fit of the measured and calculated water level in the well, as shown in Figure 6. This may be a result of the uncertainty of LPM within the Lumpfit software (Scholtysik 2015). An average reservoir temperature of 69˚C was assumed based on the measured data.

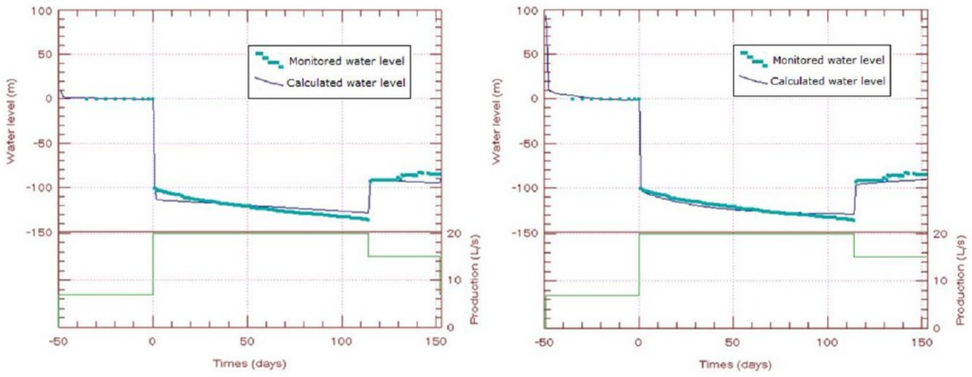


Figure 5: Monitored and calculated water level of Well HF-1 from April 9, 2013 to September 8, 2013 of the long-term production test. Calculated values are those of the LPM, where the left shows the two-tank closed model and the right shows the two-tank open model. Time t = 0 corresponds to April 9, 2013 (Shengtao 2014).

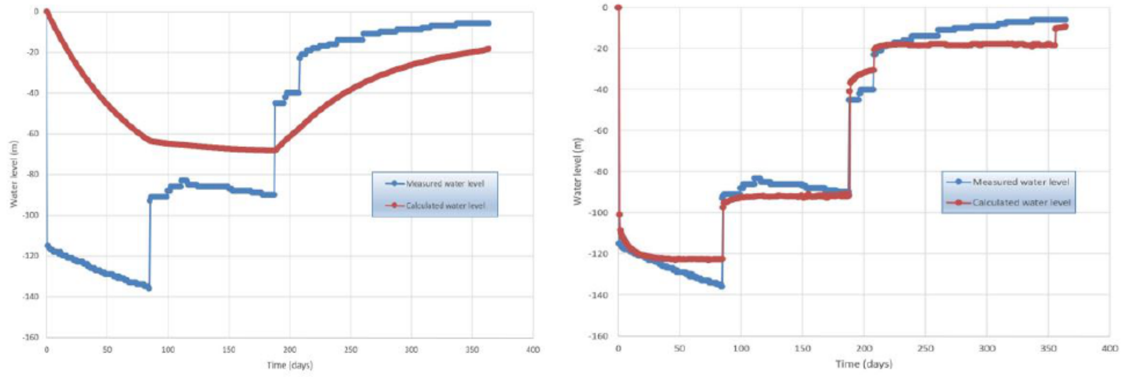


Figure 6: Monitored and calculated water level of Well HF-1 from May 9, 2013 to May 8, 2014 of the long-term production test. Calculated values are those of the LPM, where the left shows the two-tank closed model and the right shows the two-tank open model. Time t = 0 corresponds to May 9, 2013.

Based on the lumped parameter models established above, future predictions could be calculated to estimate the response of the water level (reservoir pressure) to exploitation. Ten year predictions were calculated to help gain an understanding of the general water level changes for different production flow rates (Shengtao 2014). A Monte Carlo simulation performed by Shengtao shows that if the geothermal heating system will be used for 50 years with average thermal power of 6.0 MW_{th}, a thermal water flow rate of 28.6 l/s is needed; and if the geothermal heating system will be used for 100 years with a thermal power of 3.0 MW_{th}, a thermal water flow rate of 14.3 l/s is needed (Shengtao 2014). The Monte Carlo simulation results form the basis for the prediction production scenarios; therefore the production rates were set to 28.6 l/s, 21.4 l/s, 14.3 l/s and 7.15 l/s.

As seen in Table 2, the water level behaves quite differently between the closed system and the open system. With an increasing production rate, the difference between the closed tank system and the open tank system becomes more obvious. The water level in a closed system had a greater response to large production rates than that in an open system. With the pump at a depth of 175 m, Shengtao's LPM model shows the closed tank system requiring a sustained production rate of 6.7 l/s and the open tank system requiring a sustained production rate of 26.8 l/s. The LPM model used here shows the open tank system requiring a sustained production rate of about 28.6 l/s with the pump at a depth of 175 m.

Table 2: Predicted water levels in well HF-1 after 10 years' production [m].

Production flow rate [L/s]	Based on five months data (Shengtao 2014)		Based on year-long data
	Conservative model (closed system)	Optimistic model (open system)	Optimistic model (open system)
7.15	-187	-6.5	-44
14.3	-421	-81.6	-88
21.45	-639	-140	-132
28.6	-841	-183	-176

A production rate as high as 28.6 l/s would lead to a very great water level decline if the geothermal system was a closed system; and a rate this large would cause the water level to drop down to -841 m after 10 years, which is not realistic (Shengtao 2014). However, it is also very unlikely that the system is completely closed. Furthermore, the difference in production rate for each of the optimistic approaches is very small (about 2 l/s), so it is shown that with more production data the results of the 10-year prediction are relatively the same in this case. Although the conservative approach was unable to be modeled with the year-long production data, it can be assumed that the production rate would be relatively close if a better fit were to be made. From these results, the behavior of well HF-1 is most likely to be between the 15-20 l/s production range. However, to reduce negative influence, reinjection or stimulation will be necessary, especially for large production rates if the system turns out to be relatively closed (Shengtao 2014). This is the underlying reason for creating a stimulation treatment program for well HF-1.

4.2 MFrac Model

MFrac Suite Hydraulic Fracturing Software is a comprehensive design and evaluation simulator containing a variety of options including three-dimensional fracture geometry, auto design features, and integrated acid fracturing solutions; originally designed for the oil and gas industry. Fully coupled proppant transport and heat transfer routines permit use of the program for fracture design, as well as treatment analysis (Meyer 1989). MFrac is not a fully 3-D model, but rather is formulated between a pseudo-3D and full 3-D type model with an applicable half-length to half-height aspect ratio greater than about 1/3 (Meyer 1989).

4.2.1. Stimulation Set-up

For Hoffell well HF-1, a 3-D fracture simulation model along with a complete proppant transport and fluid treatment schedule were constructed in MFrac. The goal was to create a stimulation program based on the characteristics of the well and the geothermal area in order to analyze the effects of fracture propagation. The target area was a fracture located at 1093 m depth as televiewer logs indicate good cracking and is therefore the best candidate for stimulation (Árnadóttir, Pétursson and Stefánsson 2013). Therefore, it was decided to place the packer in a conservative interval of 1070 m depth to 1110 m depth; allowing for a 40 m range of placement. Injection down the casing will be done through a 12-hour stimulation in order to show one cycle of a typical stimulation program. Proppant type used was a 20/40 mesh Jordan sand and fluid type was a low concentration water based gel. The idea of creating a water frac (WF) that has low concentrations of sand and gel will aid in creating a long fracture to intersect the main fault line. Two scenarios are created: 1) injection below a packer and 2) injection above a packer.

4.2.2. Wellbore Hydraulics

The wellbore hydraulics are defined to essentially build the well in order to calculate its total volume. First, the casing depths and dimensions are set for Hoffell well HF-1 based on drilling reports as seen in Table 3 (Kristinsson, et al. 2013). The outside diameter (OD) is specified using the MFrac internal database, where the subsequent weight and inside diameter (ID) are calculated. The lightest weight for each OD was then chosen. Although the wellbore is actually open hole after the production casing of 400 m depth, it is necessary to include the corresponding depths where additional drilling was performed in order to construct a complete well in MFrac. Drilling depths to 1404 m and 1608 m were reached using a drill bit. Up to 1404 m depth a drill bit size of 9 7/8" was used, however casings are not made in this dimension and a 9 5/8" was assumed. A drill bit size of 8 5/8" was used for the remaining 202 m to 1608 m depth. The difference in measured length and section length are not applicable for this geothermal well, as the study does not account for the use of a liner where section length is different than measured depth.

Table 3: Casing dimensions for Hoffell well HF-1.

Measured depth [m]	Section length [m]	OD [in]	Weight [lbf/ft]	ID [in]
3.9	3.9	20	94	19.124
23.8	23.8	14	50	13.344
400	400	10.75	45.5	9.95
1404	1404	9.625	29.3	9.063
1608	1608	8.625	20	8.191

4.2.3. Rock Properties

For simplification purposes, rock type was defined in three layers based on measured depth (MD), as in reality there are only slight differences in the properties of various rock types within the major governing layers of the well. The three layers of gravel, dolomite, and intrusive volcanics along with their governing properties are shown in Table 4. The permeability used in the intrusive volcanic zone is low at around 10^{-4} darcy, while the permeability in the dolomite zone is higher at around 10^{-1} darcy (Haimson and Voight 1977). Stress and stress gradient, Young's modulus, Poisson's ratio, and fracture toughness were calculated based on internal calculations in MFrac (Meyer 1986). The critical stress, defined as the minimum critical stress for the fracture to propagate in the vicinity of a constant stress field, is set to zero via the database option; i.e. only fracture toughness will be considered.

Table 4: Rock properties of Hoffell well HF-1.

Zone name	**TVD at bottom [m]**	**MD at bottom [m]**	**Stress gradient [psi/ft]**	**Stress [psi]**	**Young's modulus [psi]**	**Poisson's ratio**	**Fracture toughness [psi-in$^{1/2}$]**	**Critical stress [psi]**
Gravel	17.999	18	0.6	35.4322	4.5e+06	0.2	1000	0
Dolomite	1099.71	1100	0.83	2994.6	7e+06	0.13	1000	0
Int. volcanic	1605.6	1608	0.7	3687.41	5e+06	0.25	1000	0

4.2.4. Treatment Schedule

The total slurry volume injected was calculated assuming a constant 60 l/s flow for 12 hours and a total of 15 tons of proppant. The proppant distribution style was set using the maximum proppant concentration because a constant proppant concentration is assumed throughout the stimulation, therefore MFrac will design treatments with the last propped stage at the final proppant concentration specified. This option also creates a treatment schedule (when in auto design mode) where stages do not screen or bridge out and the maximum proppant concentration in the fracture will not exceed the maximum value specified. The proppant settling rate was interpolated assuming 0.8 mm diameter sphere/grain size (Zimmermann, Moeck and Blocher 2010) at 20˚C injection fluid temperature. Table 5 shows each of the properties defined in the treatment schedule.

Table 5: Treatment schedule for Hoffell well HF-1.

Property	**Value**	**Unit**
Slurry volume	2606	m^3
Pump rate	3600	L/min
Initial and incremental proppant concentration	0.571429	lbm/gal
Final proppant concentration	0.571429	lbm/gal
Maximum proppant concentration (at tip)	0.571429	lbm/gal
Proppant settling rate	10	cm/s

4.3 MProd Model

MProd is a single phase analytical production simulator. Although the program was designed primarily for hydraulic fracturing applications, it can also be used to explore the production potential of unfractured reservoirs. MProd has options for Production Simulation, History Match Production Simulation, and Fracture Design Optimization. Production Simulation will be used here, which allows the user to input typical production data to simulate well performance for fractured and unfractured wells. The capability to compare the output (numerical simulated results) with measured data is also provided. MProd is integrated and fully compatible with MFrac to provide full feature optimization, where the output produced by MFrac can be used by MProd.

4.3.1. Stimulation Set-up

The goal of MProd is to take the output from MFrac in order to simulate a production test performed after two scenarios of stimulation; below and above a packer. The solution is for the case of a single fracture in an infinite reservoir (i.e. open tank) where the production boundary condition is based on the net flowing pressure output of MFrac. The original production data based on flow rate from HF-1 is then overlayed for comparison in order to obtain a productivity index.

4.3.2. Formation Data

The formation data dialog box provides a location for entering the reservoir properties needed to perform a simulation. The total pay zone height is entered based on the scenario being analyzed, followed by all reservoir properties that were obtained via a Monte Carlo simulation performed by Shengtao (2014). Table 6 shows the input dialog box.

Table 6: Formation data for Hoffell well HF-1.

Property	**Value**	**Unit**
Total pay zone height	498 (below) or 670 (above)	[m]
Equivalent reservoir permeability	5.686	[mD]
Initial reservoir pressure	38.5	[bar]
Total reservoir compressibility	6.665e-08	[1/kPa]
Equivalent reservoir porosity	10	%
Equivalent reservoir viscosity	0.000399	Pa·s

5. RESULTS

5.1 MFrac

5.1.1. Fracture Propagation Solution

The fracture propagation solution is summarized in Table 7 for stimulation below and above the packer. The fracture length created after stimulation below the packer (122 m) is significantly shorter than the fracture length created after stimulation above the packer (925 m), which is attributed to permeability of the rock type defined for each stimulation zone. Frac height is calculated above and below the target fracture zone (i.e. where the packer is isolated between 1070-1110 m depth). When comparing upper frac height and lower frac height, the one that is greater is the one where injection is dominant, as seen in Figure 7. Frac width is illustrated in Figures 8 and 9 as a percentage of frac length, where frac width decreases as frac length increases.

Table 7: Fracture propagation solution. Calculated values are at the end of treatment.

Parameter	Value		Unit
	Below packer	Above packer	
Length (one wing)	122.04	924.92	[m]
Upper frac height	42.868	140.13	[m]
Lower frac height	637.1	64.037	[m]
Total frac height	679.97	204.17	[m]
Avg. hydraulic frac width	0.75954	0.12945	[in]
Net frac pressure	0.52949	10.604	[bar]

Figure 7: Upper and lower fracture zone height when stimulated below the packer (left) and above the packer (right).

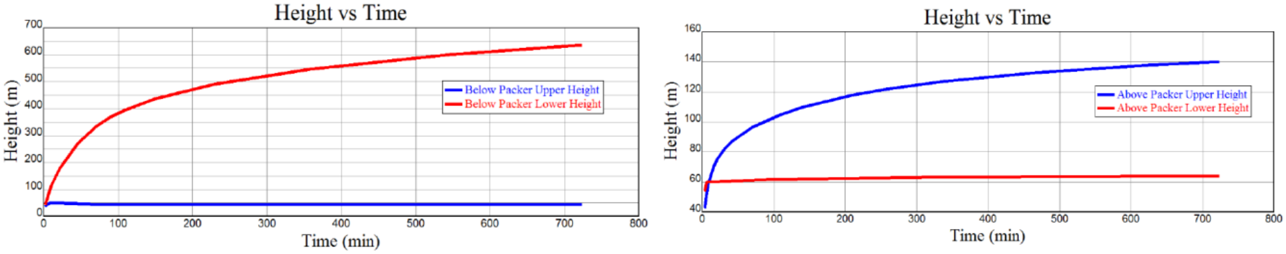


Figure 8: Frac width as a function of frac length for stimulation below the packer.

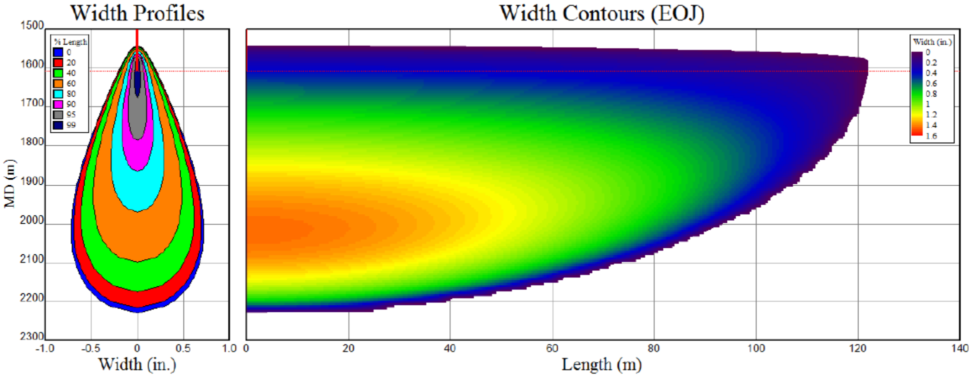
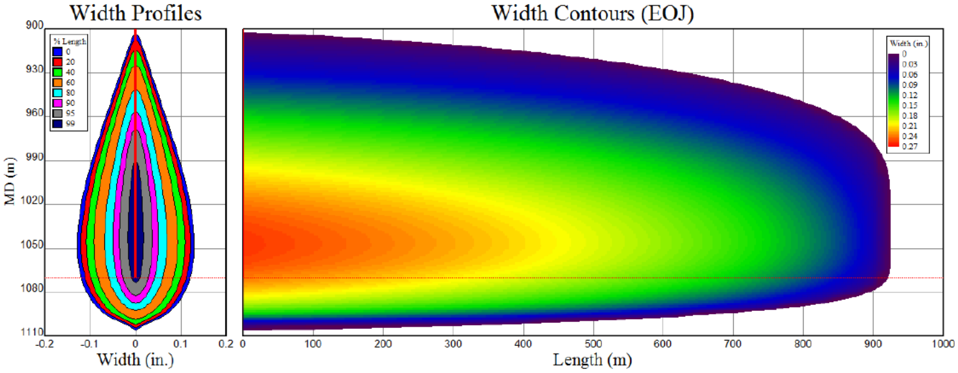
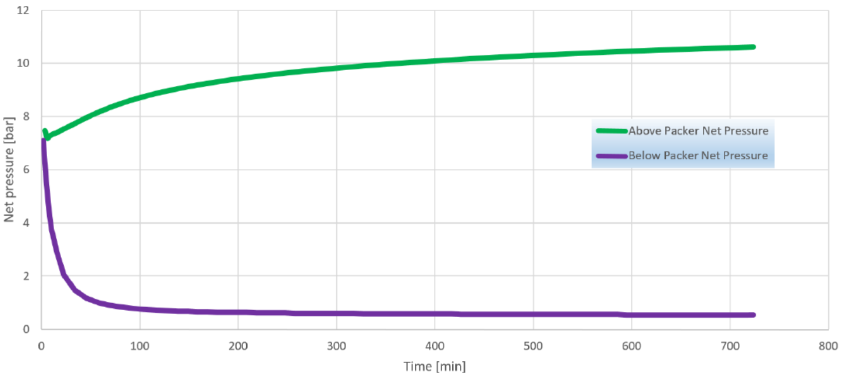


Figure 9: Frac width as a function of frac length for stimulation above the packer.



Net frac pressure is total pressure measured over the 12-hour stimulation, subtracted by pressure loss in the wellbore due to friction. Effects of net frac pressure over time are illustrated in Figure 10. Net frac pressure remains fairly constant at later stages of stimulation after about 30 minutes time, but is very low at about 0.5 bar. Net frac pressure increases with time when stimulation is done above the packer, which seems abnormal upon first glance. However this observation is consistent with pressure measured in the initial production test of Hoffell HF-1, as pressure is assumed to stabilize when measured over a longer period of time.The net frac pressure tabulated in MFrac will be used as input for MProd.

Figure 10: Net pressure measured after stimulation below and above the packer.



5.1.2. Proppant Design Summary

The proppant design summary is shown in Table 8. Proppant concentration is present at the end of job (EOJ) within the fracture after stimulation below the packer, suggesting that the proppant aided in creating the fracture. A different result is observed regarding proppant concentration in the pay zone as no proppant concentration is present, therefore no fracture was propped after stimulation. The proppant failed to create any fracture propagation that would allow for an increase in fluid production, and stimulation below the packer is therefore deemed unsuccessful. This is possibly due to the low concentration of proppant in the slurry solution, compared to large amounts of proppant used in oil and gas applications.

Proppant concentration in the fracture and in the pay zone after stimulation above the packer are present in very small amounts, but parallel the fracture length created and propped. Fracture conductivity in the pay zone is observed to be very low at about 12 mD-ft, foreshadowing indication that stimulation effects on production output are minor. Dimensionless frac conductivity is displayed via internal calculations in MFrac. The average fracture permeability increased from 10^{-1} darcy to 86.526 darcy, which indicates that stimulation was successful in terms of improving permeability of the formation.

Table 8: Proppant design summary for stimulation below and above the packer.

Parameter	Value		Unit
	Below packer	Above packer	
Frac length - created	122.04	924.92	[m]
Frac length - propped	0	92.946	[m]
Propped height (pay zone) avg.	0	16.445	[m]
Propped width (well) - avg.	0	0.13675	[in]
Propped width (pay zone) - avg.	0	0.0016789	[in]
Conc./area (frac) - avg. at EOJ	0.27101	0.040309	[lbm/ft^2]
Conc./area (pay zone) - avg. at closure	0	0.0014565	[lbm/ft^2]
Frac conductivity (pay zone) - avg. at closure	0	12.106	[mD-ft]
Dimensionless frac conductivity (pay zone)	0	3.9699e-05	
Avg. fracture permeability	0	86.526	[darcy]

5.1.3. Total Fluid Loss

The total fluid loss amounting to 1551.6 m^3 for stimulation above the packer corresponds to frac fluid efficiency, where 40% fluid efficiency above the packer was observed and suggests that there was 60% fluid loss. This corresponds to the trend associated with the Reykir hydrothermal system, where fluid losses were observed to be about the same for well with a low improvement ratio. Therefore, this shows a possible outcome for determining the magnitude of well improvement from stimulation of well HF-1.

5.2 MProd

Due to the case of an unsuccessful fracture propagation when stimulating below the packer, there is no need for further analysis. In MProd, single case fracture characteristics must be entered based on results from MFrac simulation. Permeability was calculated by MProd as 1122.22 mD based on inputs of fracture width and average fracture conductivity. Dimensionless conductivity and inverse fracture diffusivity are internally calculated in MProd. The fracture skin factor is assumed to be negligible (zero).

The net pressure data (in bar) obtained from MFrac is then used as a boundary condition for MProd simulation, while the initial production data of Hoffell well HF-1 is overlayed for comparison. A production ratio in relation to flow rate and to volume is then calculated for each iteration, where the results are summarized in Table 9 for approximately every 2 hours' iteration. The production ratio based on volume is slightly higher than production ratio based on flow rate because the average volume is used as the initial condition. For simplification of further analyses, the average productivity index of 1.096 (from flow rate) was carried forward.

Table 9: MProd production solution for Hoffell well HF-1.

Time [d]	Flow rate pre-stimulation [L/min]	Flow rate post-stimulation [L/min]	Cumulative prod. [m^3]	Avg. reservoir pressure [bar]	Flowing pressure [bar]	Prod. ratio Q/Q$_{base}$ [J/Jo(t)]	Prod. ratio V/V$_{base}$ [J/Jo|avg]
0.0023385	1797.2	2033.3	8.5725	38.5	7.4687	1.1314	1.1501
0.041997	1423.2	1572	105.81	38.5	8.2045	1.1045	1.1148
0.083469	1325.3	1457.1	195.8	38.5	8.9667	1.0995	1.1087
0.17211	1240.8	1358.6	374.69	38.5	9.6243	1.0949	1.1031
0.25468	1196.6	1307.3	532.82	38.5	10.001	1.0926	1.1003
0.33728	1166.6	1272.7	686.06	38.5	10.26	1.0909	1.0983
0.41985	1144.4	1247.1	835.75	38.5	10.452	1.0897	1.0969
0.5027	1126.7	1226.8	983.22	38.5	10.604	1.0888	1.0957

5.3 Lumpfit Parameter Model (LPM)

Goals for LPM are to evaluate changes in injectivity index, storativity, transmissivity, and productivity index after stimulation of Hoffell well HF-1. After the 12-hour stimulation operation was modeled in MProd, the production flow rate improvement ratio of 1.096 was used to scale the initial production data of flow rate versus water level. After modelling production flow rate for the 13-month interval, increases were observed from 20 l/s to 22 l/s in the first step to day 86, and from 15 l/s to 16 l/s in the second step to day 189. The remainder of the production flow rate data stayed relatively constant with only minor increases. Storativity, transmissivity, injectivity index, and productivity index are expressed in Table 10 to compare improvement ratios before and after stimulation.

Table 10: Improvement ratios for well test data after stimulation above the packer.

Parameter	**Value**			**Unit**	**Improvement ratio**
	Before stim. five months prod. test data (Shengtao 2014)	**Before stim. year-long prod. test data**	**After stim. prod. test data**		
Storativity (S)	5.65E-08	5.10204E-05	5.10204E-05	[$m^3/Pa \cdot m^2$]	1
Transmissivity (T)	1.2E-08	4.59E-07	4.78E-07	[$m^3/Pa \cdot s$]	1.041
Injectivity index (II)	3.479	1.77	1.942	[(L/s)/bar]	1.097
Productivity index (PI)	0.4084	0.0378	0.0413	[(L/s)/bar]	1.093

Once again, future predictions of production rate could be calculated to estimate the response of the water level (reservoir pressure) to exploitation. The same scenario of using ten year predictions were calculated to help gain an understanding of the general water level changes for different production flow rates (Shengtao 2014). Production rates were set to the same four limits based on Monte Carlo simulation of the Hoffell reservoir; 28.6 l/s, 21.4 l/s, 14.3 l/s, and 7.15 l/s. Upon further analysis, an additional boundary condition of 35.15 l/s was used to better measure well output, determined by adding one more increment of 7.15 l/s to the previous upper boundary condition of 28.6 l/s; or essentially modeling a sustained flow of 35.15 l/s to have about 7.5 MW_{th} reservoir capacity for a lifetime of 25 years. Changes in water level are observed based on production flow rate from initial analyses made using 5-month production data before stimulation, as well as analyses made using 13-month production data before and after stimulation. Results are tabulated for comparison in Table 11. With the pump at a depth of 175 m, a sustained production increase is seen from 28.6 l/s to 32.4 l/s.

Table 11: Predicted water levels after stimulation in well HF-1 after 10 years' production based on year-long production data.

Production flow rate [L/s]	Optimistic model (before stimulation) [m]	Optimistic model (after stimulation) [m]
7.15	-44	-38
14.3	-88	-77
21.45	-132	-115
28.6	-176	-153
35.75	N/A	-193

6. CONCLUSIONS

Stimulation above the packer was successfully modeled in MFrac and MProd, while stimulation below the packer had inconclusive results for the case study of Hoffell well HF-1. However, this does not mean that stimulation above the packer is a better method for use across other geothermal areas as there are several uncertainties about the case study. The productivity improvement was minor with only a 1.096 improvement ratio, therefore the well is not a good candidate for realistic stimulation operations. In addition, very optimistic production flow rates were measured in the open tank geothermal system model, which further indicates that a different candidate well would have been more appropriate for analyses moving forward.

Sensitivities were observed within MFrac, MProd, and Lumpfit software. These include MFrac's proppant concentration and stimulation interval, MProd's solution methodology for matching short-term and long-term production test data, and Lumpfit's correlation with closed tank geothermal systems using long-term production test data. Internal programming work within MFrac, MProd, and Lumpfit software is necessary to account for varying geothermal circumstances.

Specific to Lumpfit, the software is meant to be used when there is limited data available, however it was used here to compare original models done by Shengtao (2014) for the case study of well HF-1 in the Hoffell low temperature geothermal field. A different program capable of predicting reservoir properties using long-term production data would have been more applicable to use moving forward with this case study. Ultimately, this study initiates first attempts in modeling stimulation for direct use; showing there is proof of concept.

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