Hydraulic and Thermal Stimulation Program at Raft River Idaho, A DOE EGS

Jacob Bradford[1], John McLennan[1], Joseph Moore[2], Robert Podgorney[3], and Shashank Tiwari[1]

[1]Department of Chemical Engineering, University of Utah, Salt Lake City UT, USA
[2]Energy & Geoscience Institute at the University of Utah, Salt Lake City UT, USA
[3]Idaho National Laboratory, Idaho Falls ID, USA

ABSTRACT

A Department of Energy Enhanced Geothermal System (EGS) stimulation program has injected over 254 million gallons of water into the well RRG-9 ST1 since the summer of 2013. Three major stimulations have been conducted during the program increasing injection flow rates from less than 20 gpm to 550 gpm. Geologic, water chemistry, microseismic activity, and borehole imaging data have been used to develop a conceptual model describing possible flow paths of this injected water. This model contains two major fracture zones one of which intersects the RRG-9 ST1 wellbore. Modified Hall and injectivity index plots constructed using injection flow rates, surface temperatures, and wellhead pressures show steady improvement in the injectivity of the well. The injectivity index has risen from 0.15 gpm/psi to 2.0 gpm/psi. A pressure falloff test conducted on April 28, 2015 indicates a reservoir permeability of 1,220 md and -5.38 skin factor. The well stimulation program was simulated numerically using an Idaho National Laboratory reservoir simulation code, FALCON. These simulations show a significant increase in the permeability of connecting fracture pathways after each stimulation event.

Introduction

The Raft River geothermal field is the site of a Department of Energy Enhanced Geothermal System (EGS) stimulation demonstration project. It is located in Cassia county Idaho, roughly 100 miles northwest of Salt Lake City, Utah. The field is owned and operated by U.S. Geothermal Inc. Four production wells, RRG-1, 2, 4, and 7 provide approximately 5,000 gpm to a binary power plant which generates between 10.5 to 11.5 MWe. Injection into the reservoir is provided by 4 wells, RRG-3, 6, 11, and recently 9 ST1 (Fig. 1).

Injection well RRG-9 ST1 has been the target well for a Department of Energy EGS stimulation demonstration project. Located approximately one mile south of the
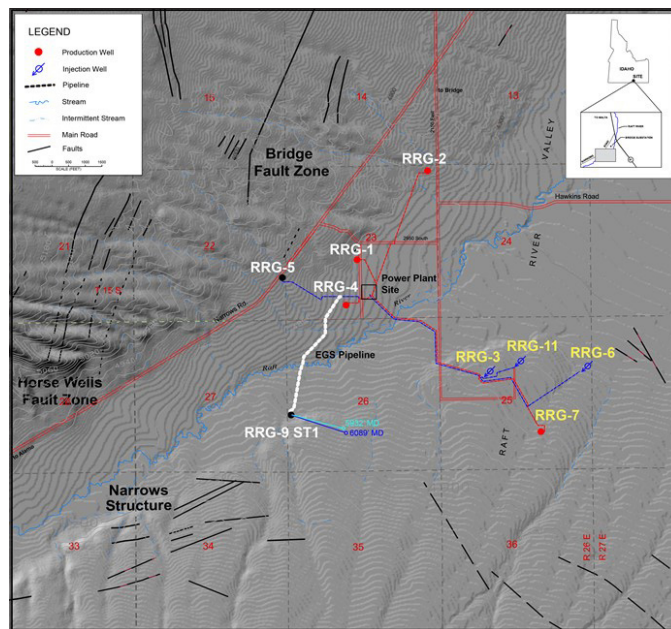

Figure 1. Map of the Raft River geothermal field displaying well locations and infrastructure. RRG-9 ST1 is connected to the plant by a 10 inch pipeline shown in white. The majority of the production wells are located in the northwest part of the field except for RRG-7. All injection wells except for RRG-5 are in the southeastern part of the field (from Williams et. al. 1982).

main power plant, the original well was sidetracked and cased to a measured depth of 5,551 ft. and deepened to a measured depth of 5,932 ft. in 2012. Since then, three major hydraulic stimulations were conducted to improve well injectivity.

Conceptual Model

Geologic, water chemistry, microseismic activity, and borehole imaging data were used to develop a conceptual model of the reservoir surrounding RRG-9 ST1. The geology of Raft River is complex. The field is located at the intersection of several fault trends. The wells at Raft River pass through nearly 5,000 ft. of discontinuous Tertiary and Quaternary volcanic and volcanoclastic rocks that overlie metamorphic Precambrian basement rocks. Fluid is primarily produced and injected back into the Elba Quartzite, located in the Precambrian basement. The average resource temperature of the produced fluid is 150 °C. The RRG-9 ST1 wellbore encountered the Elba Quartzite at a measured depth of 5,300 ft. and passes through nearly 600 ft. of that formation before terminating in an intrusion of the quartz monzonite at a measured depth of 5,932 ft. Four distinct water chemistries are represented in the Raft River field. Two of the identified waters are surface waters while the other two are deeper geothermal waters. Geothermal waters collected from the wells on the northwest side of the field (RRG-1, 2, 4, and 5) have lower salinities than those collected from the wells on the southeast side of the field (RRG-3, 6, 7, 11). Ayling and Moore (2013) have proposed that a northeast-striking shear zone divides the northwest and southeast sides of the field and acts as a fluid barrier. This barrier is commonly referred to as the Narrows zone. The implication of this finding is that stimulation water injected into RRG-9 ST1 is not flowing beyond the Narrows zone to the north of the well. A further description of the geology and geochemistry of Raft River can be found in Konstantinou et al. (2012) and Nash and Moore (2012). The Narrows zone has also been identified by microseismic activity likely occurring as a result of the stimulation program (Table 1).

Table 1. Summary of RRG-9 Stimulation Program.

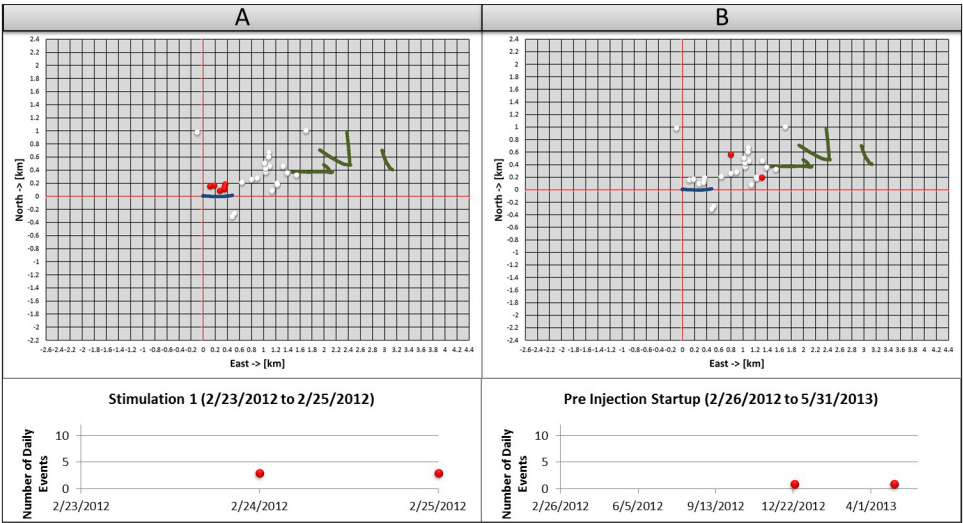| Date	Event
February 2012	Stimulation 1
March 2012 to June 2013	RRG-9 ST1 was shut-in
June 2013 to August 2013	Injection resumed at RRG-9 ST1
August 2013 to September 2013	Stimulation 2
September 2013 to April 2014	Continuous injection of plant water
April 2014	Stimulation 3
April 2014 to Present	Continuous injection of plant water

With few exceptions, injection into RRG-9 ST1 has been continuous since June 2013 and is currently ongoing. Since August 2010, approximately 165 microseismic events have been recorded at Raft River, ranging from magnitude -1 (recording threshold) to +1.3. The location and timing of microseismic events during the stimulation program are used to determine/validate the flow path of the injected water, which corresponds to the Narrows zone. Figure 2 shows the recorded seismic events that have occurred during key stages of the stimulation program (seismic data provided by Lawrence Berkeley Induced Seismicity EGS).

Both stimulation 2 and stimulation 3 generated events in the same area as the location of a major fracture zone intersecting the RRG-9 ST1 wellbore; see the region outlined in black in Figure 2C and Figure 2E. Most of the seismic events follow a northeast trend consistent with the location of the Narrows zone. The placement and timing of the events show fluid flow from RRG-9 ST1 into an intersecting fracture zone connecting into the Narrows zone. After completion, the openhole section of the well was imaged. Eighty two naturally occurring fractures were mapped intersecting the wellbore, including a major fracture zone at 5,645 ft. MD to 5,660 ft. MD (Bradford et al. 2015).

A conceptual model has been developed to represent flow of the injected water along inferred large-scale fluid pathways. The model consists of the Narrows zone that inhibits fluid flow to the northwest but provides fluid pathways along its length to the northeast. Due to changes in the orientation of fracture gradients to the southwest and the location of seismic events (seen in Figure 2) it is presumed that the majority of the fluid flows to the northeast; see Bradford et al. 2015. From recorded seismic events it is
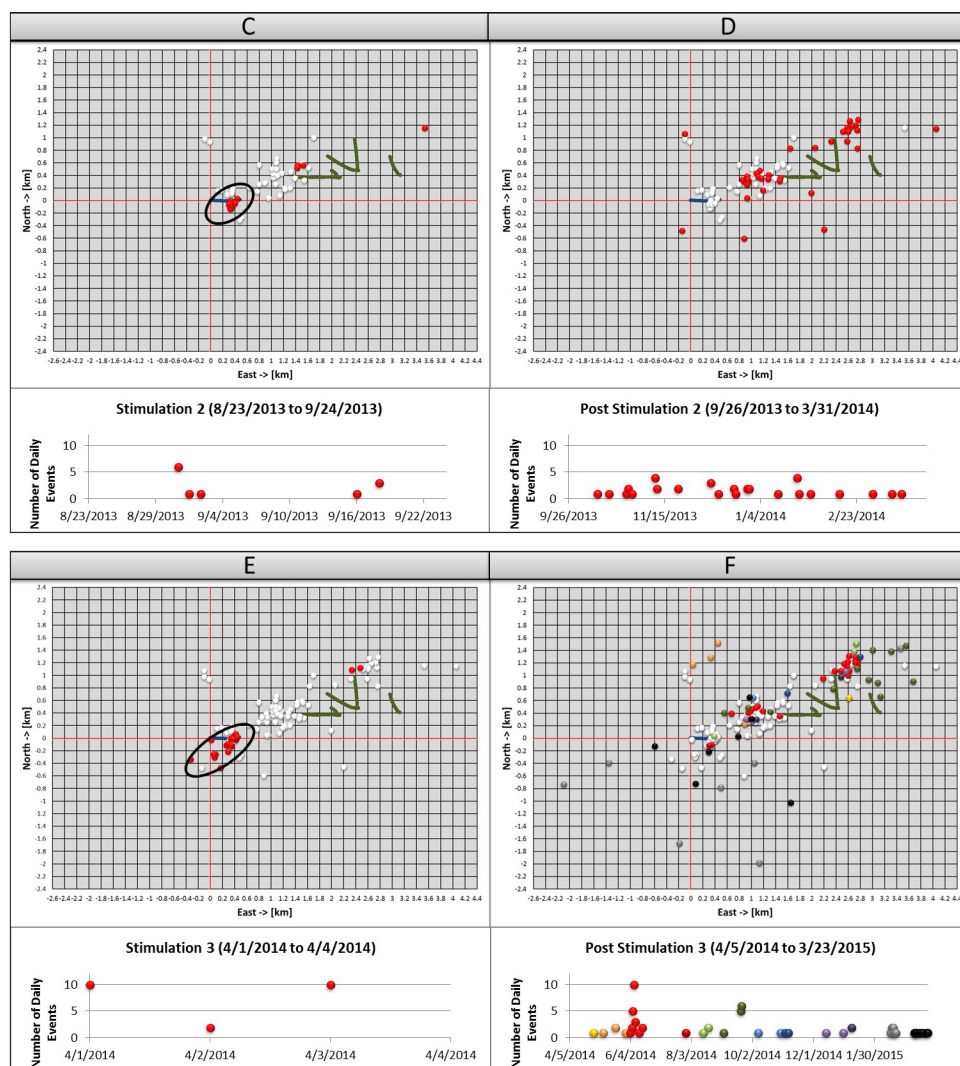
Figure 2. For each time period a map of seismic events is plotted above a histogram displaying the number of seismic events. All distances given in the maps are relative to the RRG-9 ST1 wellhead. The RRG-9 ST1 well trajectory is represented by the blue line while the other injection well trajectories (RRG-3, 6, and 11) are shown in green. Events occurring during the selected time periods are shown in red while previous events are in white. The post stimulation 3 time period (F) is further broken down by month and color coded accordingly to more clearly show the progression of events along the Narrows zone. Notice the green events of October 2014 moving beyond the red events of June 2014. A Stimulation 1. B Pre Injection Startup, only two events occurred during this time period. C Stimulation 2, the events occurring in the intersecting fracture zone are circled. D Post Stimulation 2. E Stimulation 3, the events occurring in the intersecting fracture zone are circled. F Post Stimulation 3, events are broken down by month to show the progression of the fluid along the Narrows zone.
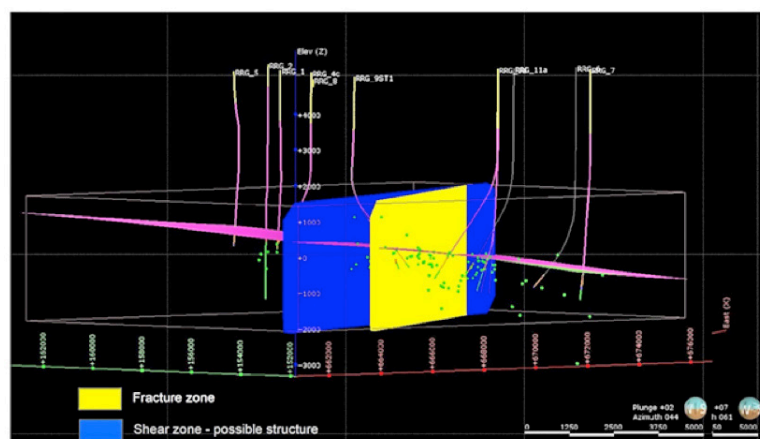

Figure 3. Conceptual model for the RRG-9 ST1 stimulation program. The blue plane is the Narrows zone, the yellow plane is the fracture zone that intersects the RRG-9 ST1 wellbore. The pink plane represents the Tertiary-Precambrian contact. The green dots are the recorded seismic events, most of which occur below the pink plane in the Precambrian basement.

hypothesized that the Narrows zone is intersected by the major fracture zone identified in the RRG-9 ST1 wellbore (Fig. 3).

In this model fluid injected into RRG-9 ST1 flows into the fracture zone between 5,645 ft. and 5,660 ft. MD. The injected water flows along this fracture zone until it intersects the Narrows zone. After reaching this intersection, the water continues flowing to the northeast along the trajectory of the Narrows zone.

RRG-9 ST1 Stimulation Activities

RRG-9 ST1 was hydraulically stimulated shortly after drilling in February 2012. Due to uncertainty in the amount of water the well would initially accept this initial stimulation was a short test. Flow rates started at 210 gpm and were increased in steps up to 756 gpm with a maximum wellhead pressure of 1,150 psig.

Following this stimulation, the well was shut-in for a year and a half while a 10 inch pipeline was constructed from the plant to the wellhead and Department of Energy environmental reviews were completed. Injection resumed during the summer of 2013 using injection water from the plant. Instead of an expected flow rate on the order of 220 gpm at a wellhead pressure of 280 psig, a rate of less than 40 gpm was achieved during the first few months of injection. A second stimulation was conducted at the end of August, 2013 using elevated flow rates and a mixture of plant injection water and cold well water. Using small agricultural pumps the flow rate was increased to 170 gpm for one week. The following week the injection rate was raised to 330 gpm. Injection was then switched from plant injection water to cold well water averaging 13 °C at 191 gpm for an additional week. After this stimulation regular injection into the well was resumed at 280 psig. Following this second stimulation flow rates increased from 50 gpm to 120 gpm. Injection was maintained throughout the winter of 2013 and the spring of 2014.

In April 2014 a third stimulation was conducted using pump trucks. 10 °C to 15 °C water was injected over a three day period. On the first day, flowrates of 850 gpm at a wellhead pressure of 840 psig where achieved. This wellhead pressure was much lower than the 1,150 psig recorded during the first stimulation at comparable rates. On the second and third days flow rates were raised to 1,260 gpm at a wellhead pressure of 980 psig for 6 hours before excessive vibration forced the flowrate to be cut back to 850 gpm. Following the third stimulation, plant water injection resumed at 280 psig and the current flow rate is 550 gpm. Since injection began in 2013 over 254 million gallons of water have been injected into RRG-9 ST1. Flow rates have increased from less than 40 gpm to 550 gpm (Fig. 4).

Stimulation Program Analysis

Since injection began in the summer of 2013, wellhead pressure, injection rate, and surface injection temperature data have been collected at RRG-9 ST1 and processed. One assessment method, the modified Hall's technique, uses a plot of cumulative bottomhole flowing pressure versus the cumulative volume injected to infer reservoir properties, see Earlougher 1977 and Bradford et al. 2015. A modified Hall plot has been constructed for the RRG-9 ST1 stimulation program (Fig. 5).

Each stimulation has resulted in a decreasing slope throughout the stimulation program (Figure 5) indicating that an increase in permeability, a decrease in the dimensionless pressure, and/or a decrease in the skin factor is occurring. These changes can be attributed to hydraulically and thermally opening/reopening of existing or new fracture pathways around the RRG-9 ST1 wellbore.

Another technique employed to evaluate injection performance is the injectivity index. The injectivity index is the injected flow rate divided by the wellhead pressure. This is plotted versus time. An injectivity index plot constructed for the RRG-9 ST1 stimulation program is shown in Figure 6.
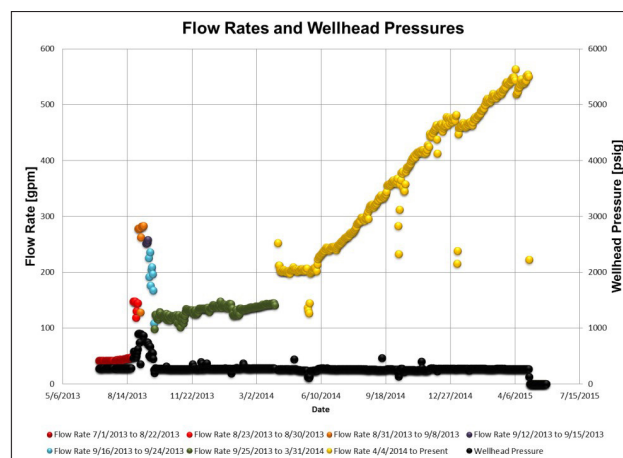

Figure 4. Stimulation program flow rates and wellhead pressures. Flow rates are color coded based on the time period covered while the wellhead pressure is shown in black.
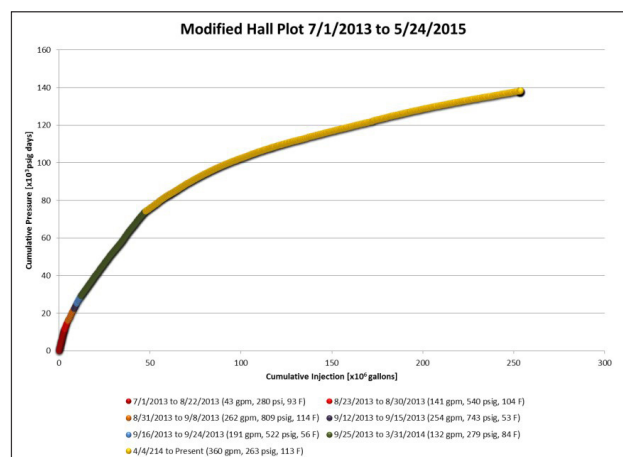

Figure 5. Modified Hall plot for the RRG-9 ST1 stimulation program. This plot shows a continuous decrease in the slope indicating an increase in permeability and/or and decrease in the dimensionless pressure and skin factor.
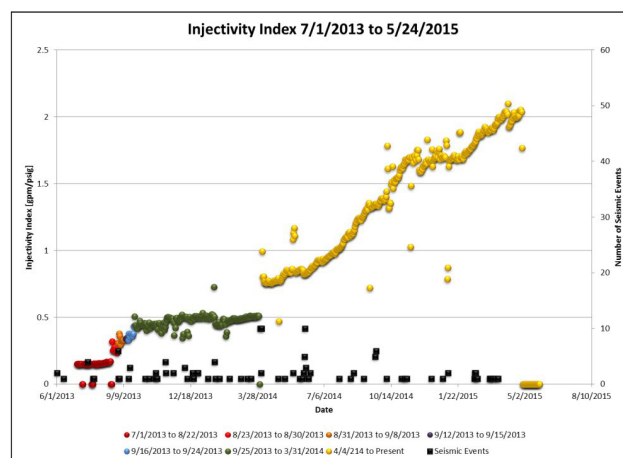

Figure 6. Injectivity index for the RRG-9 ST1 stimulation program. Also shown are the number of seismic events per day. There is a correlation between the number of seismic events and increases in the injectivity index.

Figure 7. Pressure Falloff test Data. Pressure is in blue and temperature is in red.

The injectivity index has increased after each stimulation event. After the third stimulation the injectivity index has rapidly increased indicating that new reservoir volume is being created by the stimulation program. Since July of 2013 the injectivity index has risen from 0.15 gpm/psi to 2.0 gpm/psi. A correlation exists between the number of seismic events and an increase in the injectivity index, especially after the third stimulation.

On April 28, 2015 RRG-9 ST1 was shut in to conduct a pressure falloff test. A sensor had been placed slightly above the casing shoe prior to the shut-in to monitor pressure and temperature (Fig 7).
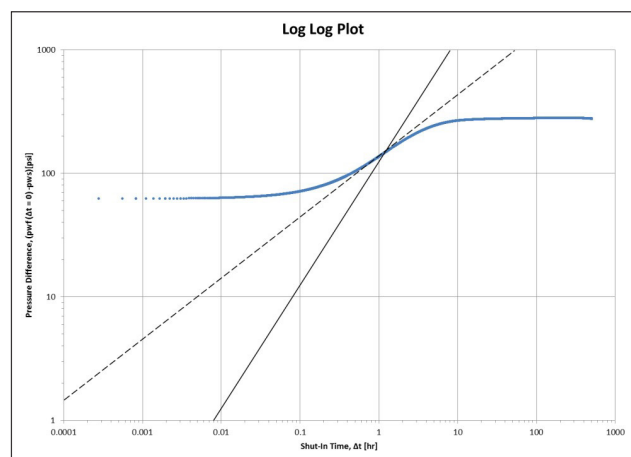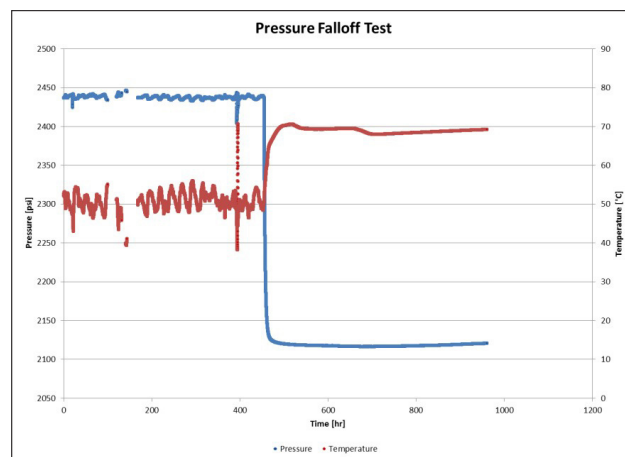

Figure 8. Log-Log Plot. The blue line is pressure. The black line represents the unit slope while the dashed black line is the 1/2 unit slope.

Figure 9. Semi-Log plot generated by Kappa Engineering's well testing software Ecrin.

Figure 10. The RRG-9 ST1 stimulation program FALCON model. The model is 10 km by 10 km. The Narrows zone is divided into three sections colored in green. This allows for greater flexibility in property assignment to better model the size and density of fractures associated with the Narrows zone. This is consistent with work done by Plummer et al. (2015). Preliminary simulations assigned all three zones the same parameter values. The fracture zone intersecting the RRG-9 ST1 wellbore is shown in red.

Log-log diagnostic and semi-log plots were prepared for the pressure falloff test to estimate the permeability and skin factor around the wellbore (Fig 8 and Fig 9).

Kappa Engineering's well testing software Ecrin uses the slope of the curve after wellbore/fracture system storage effects end along with the infinite acting radial flow equation to estimate the permeability and skin factor of the system. Analysis indicates a permeability of 1,220 md and a skin factor of -5.38 as a result of the stimulation program at Raft River. The skin is in line with what one would expect for a substantial fracture. The permeability has to indicate the dominance of an exceedingly large and stable fracture system. By stable, the implication is that it is self-propped. Notice that injection is always at pressures below the frac gradient, implying that these fractures are opened by thermally-related shrinkage, sliding, and self-propping.

Numerical Modeling

FALCON is a finite element reservoir modeling program created by the Idaho National Laboratory. It is being used to simulate the multi-year stimulation program conducted on RRG-9 ST1. From the conceptual model presented earlier, a 10 km by 10 km section of the Raft River reservoir surrounding RRG-9 ST1 was constructed in FALCON (Fig 10).

A continuum approach was taken to model both the Narrows zone and the major fracture zone intersecting RRG-9 ST1. In FALCON, this is accomplished by assigning higher permeability and aquifer compressibility values to elements that contain either the Narrows zone or the fracture zone. FALCON solves for the pressure both in the fracture and matrix nodes using Equation 4

$$\acute{q} = 0 \tag{4}$$

where ϕ is porosity, ρ is the fluid density, t is the time, α is the aquifer compressibility, p is the pressure, k is the permeability, μ is the fluid viscosity, g is the gravitational acceleration vector, and $\acute{q}$ is the source/sink term used to simulate injection into an element. Permeability in the fractures is allowed to change through a simple pressure-dependent relationship given in Equation 5

$$k = k_0 e^{\left(f_k(p-p_0)\right)} \tag{5}$$

where k_0 is the base permeability, f_k is the permeability throttle, an empirical constant which sets how much the permeability is allowed to change based on the pressure difference, and p_0 is the initial reservoir pressure. Further details of how FALCON solves subsurface reservoir problems have already been given in Smith et al. (2013). The RRG-9 ST1 stimulation program - from July 1, 2013 to February 15, 2015 – was simulated using FALCON. Injection into the reservoir occurs in the southwest end of the fracture zone using the source/sink term in Equation 4. This is in accordance with the conceptual model. The source/sink term was updated using the daily average flow rates measured at the RRG-9 ST1 wellhead. Density and viscosity were held constant for the preliminary simulations. Step changes to the base permeability and storage (through aquifer compressibility) of the fractures were implemented after each of the two stimulation events. By adjusting the base permeability and aquifer compressibility (storage) of the fractures a pressure match for the stimulation program was obtained (Fig. 11).

Stage 1 of the simulation represents the time period before and during the second stimulation where flow rates were low at a wellhead injection pressure of 280 psig. As a result permeability values for both the Narrows zone and near-well fracture zone were small. Permeability
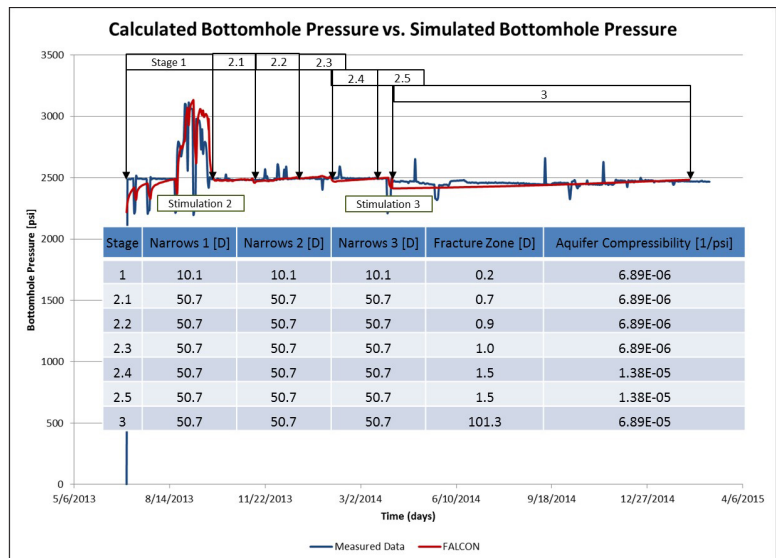

Stage	Narrows 1 [D]	Narrows 2 [D]	Narrows 3 [D]	Fracture Zone [D]	Aquifer Compressibility [1/psi]
1	10.1	10.1	10.1	0.2	6.89E-06
2.1	50.7	50.7	50.7	0.7	6.89E-06
2.2	50.7	50.7	50.7	0.9	6.89E-06
2.3	50.7	50.7	50.7	1.0	6.89E-06
2.4	50.7	50.7	50.7	1.5	1.38E-05
2.5	50.7	50.7	50.7	1.5	1.38E-05
3	50.7	50.7	50.7	101.3	6.89E-05

Figure 11. Pressure history match for the RRG-9 ST1 stimulation program. The blue line is the calculated bottomhole pressure while the red line is the simulated bottomhole pressure obtained using FALCON. For stage 1 the permeability of the fracture zone was considered to be the controlling resistance to fluid flow. As a result it was assigned a low permeability given the low flow rates of the early months of stimulation program. Stage 2 was further broken down into five subsections to provide a better history match. In stage 2 and stage 3 the permeability of the Narrows zone was increased to represent greater access of the fluid to this zone as seen in the seismic activity. In stage 3 the aquifer compressibility of the fractures was significantly increased to represent the generation of reservoir volume seen in the injectivity index plot.

in the Narrows zone was increased after the second stimulation to represent better access to this zone – as was seen in the seismic data. The permeability in the fracture zone was also increased to represent the opening of fractures due to the elevated injection rate during the second stimulation. During the third stage of the simulation the fracture permeability was raised again to represent fracture pathways opened by (or created by) the high pressure stimulation. Aquifer compressibility (fracture storage) was also increased in this stage to account for the increase in reservoir volume implied by the injectivity index. The results from the numerical simulation show an increase in the permeability of the fracture zone from nominally 0.202 D to 101 D due to the stimulation program. The values are large compared to those obtained from the falloff test. Predicted permeabilities are in general concurrence with the falloff interpretation to the end of stage 2. However the model does show conceptually how these values change during the course of the stimulation program.

Conclusions and Future Work

A three-stage stimulation program implemented at RRG-9 ST1 has increased the injection flow rate from less than 40 gpm to 550 gpm. Over 254 million gallons of water have been injected into the well since the summer of 2013. A conceptual model consisting of the Narrows zone and a fracture zone intersecting the RRG-9 ST1 wellbore has been developed to explain possible flow pathways of the injected water. Analysis of the injection flow rates, surface injection temperature, and wellhead pressure indicate that fracture pathways around RRG-9 ST1 have been hydraulically and thermally opened or reopened as a result of the stimulation program. The injectivity index of the well has risen from 0.15 gpm/psi to 2.0 gpm/psi since the beginning of the stimulation program. Preliminary results from a pressure falloff test conducted on April 28 give an estimated permeability and skin factor of the system of 1,220 md and -5.38 respectively. The stimulation program has been numerically modeled using Idaho National Laboratory's reservoir simulation code FALCON. These simulations show an increase in the permeability of the intersecting fracture zone from 0.202 D to 101 D due to the stimulation program. These tools show that the stimulation program has been very successful in improving the injectivity of the well which is now being commercially used by U.S. Geothermal Inc. Injection into RRG-9 ST will continue. Future plans include analysis of the stimulation program's effect on the other injection wells during a planned plant shut down as well as energetically stimulating the well using rocket propellant.

Acknowledgements

Nomenclature

α	*aquifer compressibility*
f_k	*emperical permeability throttle constant*
g	*gravitational acceleration vector*
h	*formation height*
k	*permeability*
k_m	*base permeability*
p	*pressure*
p_0	*inital reservoir pressure*
p_D	*dimensionless pressure*
p_e	*reservoir pressure*
p_f	*pressure loss due to friciton*
p_{tf}	*wellhead pressure*
Δp_{tw}	*hydrostatic pressure*
q	*injection flow rate*
$\dot{q}$	*injection source/(sink term)*
r_e	*reservoir radius*
r_w	*effective wellbore radius*
s	*skin factor*
t	*time*
W_i	*cumulative fluid volume injected*
μ	*viscosity*

Bradford, *et al.*

ρ *fluid density*
ϕ *porosity*

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