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Thermal Stimulation and Injectivity Testing at Raft River, ID EGS Site

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ABSTRACT

The Raft River geothermal field is the site of an innovative Department of Energy Enhanced Geothermal System (EGS) project to determine the viability of using combined thermal and hydraulic stimulation techniques to improve energy production. Well RRG-9 is currently undergoing a stimulation program using injectate from the US Geothermal Raft River Power Plant and cold water from a cooling tower make-up water well. The stimulation began on 13 June 2013 with injection from the power plant at a temperature of about 39 °C and a pressure of 275 psig. Next, two positive displacement plunger type pumps were used to increase the injection pressure and flow rate for about one month. The highest rate achieved was 258 gpm at a pressure of 741 psig. During this time, fluid from the cooler water well was injected for about 2 weeks at various pressures. Then, the pumps were removed and plant injection resumed on 25 September. Plant injection will continue until the spring of 2014, when a high pressure hydraulic stimulation will be conducted. A series of seismic monitoring stations deployed around the well are providing data on seismic events occurring at the site. Over the past year, 51 microseismic events have been recorded, all less than Magnitude 1.

During injection, several diagnostic tests were conducted to gain a better understanding of the well and reservoir. A step-rate test was performed on 22 August to measure the in-situ stress and aid in modeling in-situ fractures. A tracer was injected into the well on 9 September. No tracer was detected in adjacent production wells after several months. A second borehole televiewer survey was conducted for comparison to pre-stimulation images. A third borehole televiewer survey is planned after the high pressure stimulation.

Injection test data is evaluated in real time. A modified Hall plot analysis indicates the effective permeability is increasing. The injectivity index supports the results of the modified Hall plot analysis. As the thermal stimulation has continued, the injectivity index has consistently followed an upward trend from 0.1 gpm/psi to 0.53 gpm/psi.

1. INTRODUCTION

Located in southeastern Idaho, 100 miles northwest of Salt Lake City, UT, the Raft River geothermal site was initially developed between 1974 and 1982 by the Energy Research and Development Administration (ERDA), and later the U.S. Department of Energy (DOE) as a geothermal demonstration project (Figure 1)

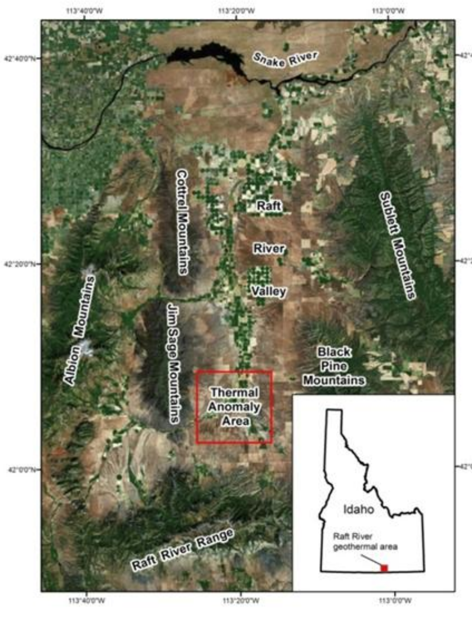

Figure 1: Raft River Geothermal Area.

U.S. Geothermal, Inc. currently operates a 13 MWg binary power plant at the site, using 4 production wells to supply roughly 5,000 gpm total flow, and three injection wells. The field is presently the location of a DOE EGS project to determine the viability of combined thermal and hydraulic stimulation programs, and to bring more of the geothermal resource into production by using RRG-9 as a new injection well.

The geology of the area is complex. Approximately 5,000 ft. of discontinuous Quaternary and Tertiary volcaniclastic and volcanic rocks are present above the Precambrian metamorphic basement, which is the location of the geothermal reservoir. The primary reservoir is the Elba Quartzite, a fine-grained metamorphosed quartz-rich sandstone. Two major fault zones have been identified on the west side of the Raft River Valley, the Bridge and Horse Wells Fault Zones. Both zones strike approximately north-south (Figure 2).

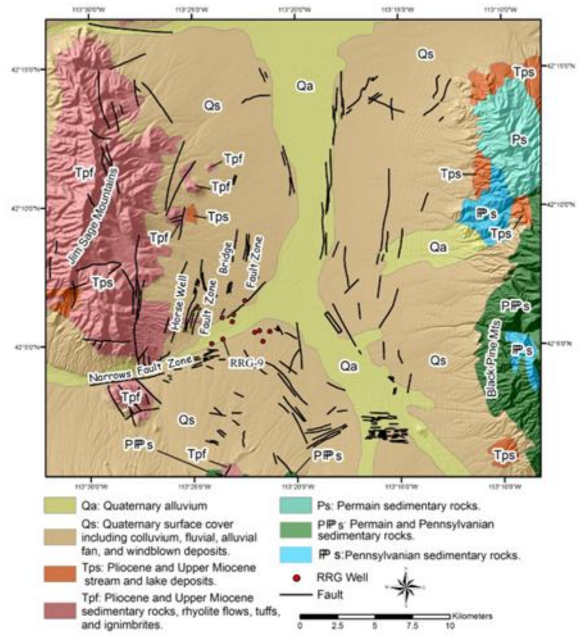

Figure 2: Surface geology map (after USGS, 2005; Link 2002: Williams et al., 1974)

RRG-9 is located southwest of the main wellfield, and was originally drilled to test the intersection of the Narrows and Bridge Fault zone (Figure 3). The Narrows zone appears to divide the geothermal system into two major compartments. RRG-5 drilled northwest of the Narrows zone produced a hydraulic fracture with a NNE trend (N29°E, Keys, 1980). RRG-4 drilled southeast of the Narrows zone was also stimulated and produced a hyudraulic fracture trending slightly north of east (N72°E, Keys, 1980). In 2012 RRG-9 was sidetracked and deepened to a true vertical depth of 5,392 ft, placing it in the Quartz Monzonite formation, which is directly below the Elba Quartzite the primary target for the thermal and hydraulic stimulation program. An 8-station microseismic array was installed around RRG-9 in 2013, with the geophones placed in boreholes to a depth of approximately 300 feet (Figures 4). The array has detected events to magnitudes as low as magnitude -1.

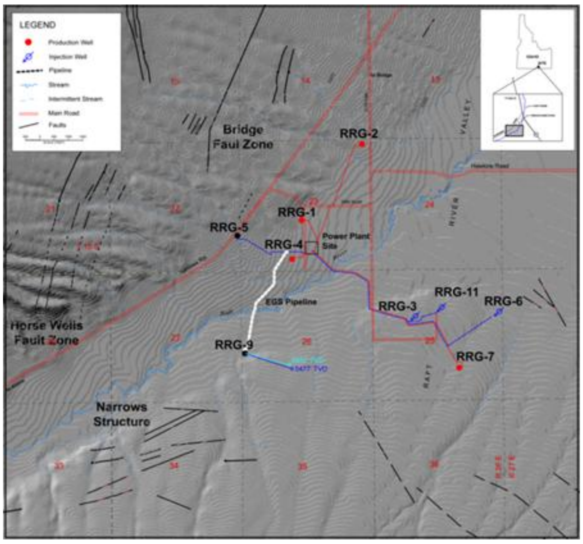

Figure 3: Location of wells and infrastructure at the Raft River Geothermal site.

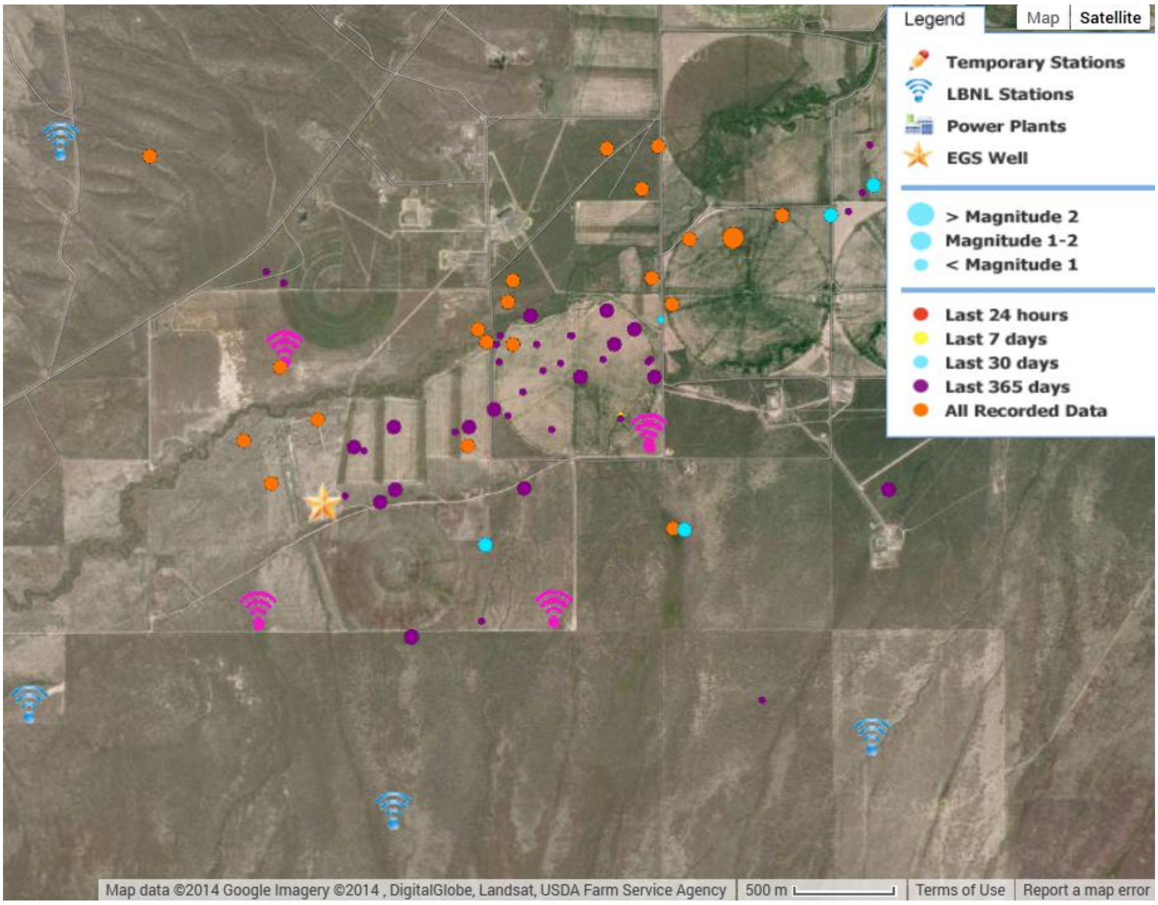

Figure 4: Overhead view of the Raft River field showing the position of seismic monitoring stations.

2. INJECTION STIMULATION PROGRAM AT RRG-9

The objective of the stimulation program currently underway at RRG-9 is to improve the injectivity of the well. The first phase began on 13 June 2013, using plant injectate at temperatures ranging from 39 °C to 46 °C. Initially, the well accepted approximately 43 gpm of plant injection water at an average wellhead pressure of 280 psig. A 10 inch injection pipeline connects the RRG-9 wellhead to the Raft River plant (Figure 5). This line is used to transport the plant injectate to the wellhead. The average temperature of the plant injectate, which leaves the plant at 44 °C, decreased to a daily average of 39 °C due to a 1 mile long uninsulated pipeline. Table 1 lists the average measured flow rates and temperatures for each phase. To increase the injection pressure, two HP-165m plunger pumps were installed at RRG-9 (Figure 6).

Figure 5: Pipeline sending injectate from 10" injection line into side outlet of RRG-9 with ultrasonic flow meter transducers mounted on 3" pipe.

Table 1: Average Injection Flow Rates and Temperatures.

Source	Time Period	Flow Rate (gpm)	Average WHP (psi)	Temperature (°C)
Plant Injectate	13-Jun to 20-Aug	43	280	39
Plant Injectate	23-Aug to 30-Aug	141	540	40
Plant Injectate	31-Aug to 8-Sep	262	809	46
Cold Well Water	12-Sep to 15-Sep	254	743	12
Cold Well Water	16-Sep to 24-Sep	191	522	13
Plant Injectate	25-Sep to 2-Dec	122	272	30
Plant Injectate	3-Dec to 10-Feb	135	283	26

Figure 6: HP-165m plunger pumps installed next to RRG-9 to increase pressure of injection stimulation.

The pump rate was increased in a stepwise manner over a two week period from 23 August to 8 September, reaching a maximum of 283 gpm at a pressure of 862 psig. The auxiliary pumps were used in a third stage of injection beginning on 12 September to inject the cooler well water at various rates. The highest rate achieved was 258 gpm at a pressure of 741 psig. The pumps were removed and the plant injection resumed on 25 September. The second phase of injection included temperatures ranging from 12 °C to 30 °C. Injection will continue until the spring of 2014, when a high pressure hydraulic stimulation will be conducted. Figure 7 displays a schematic of the RRG-9 wellhead setup.

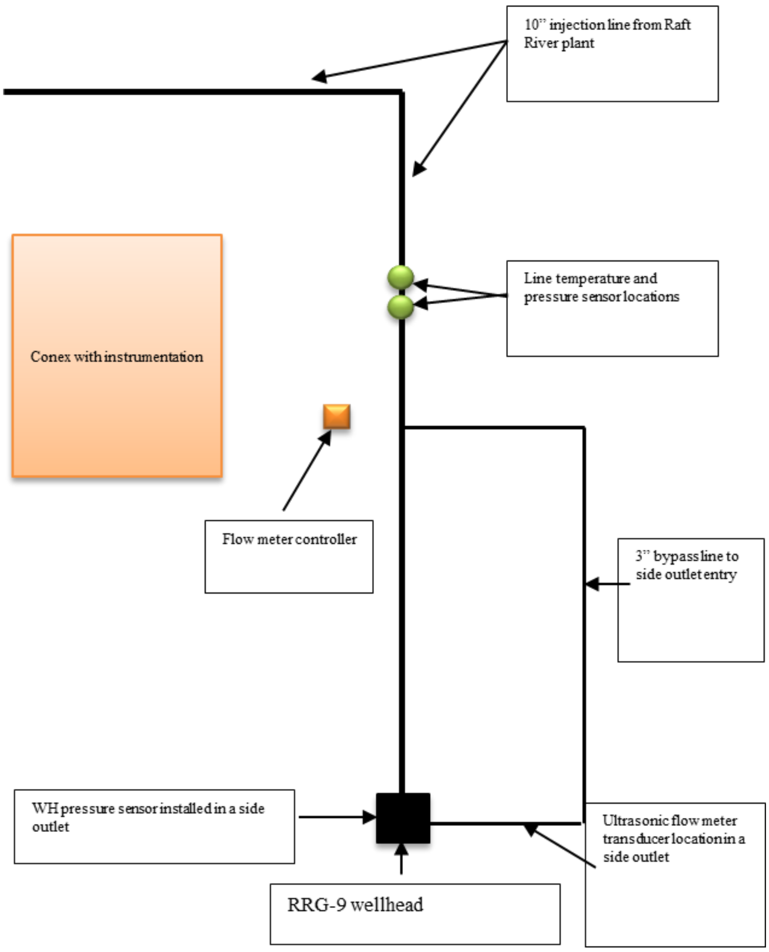

Figure 7: Schematic layout of the RRG-9 area and instrumentation.

3. DIAGNOSTIC TESTING AT RRG-9

Several types of diagnostic tests have been conducted at RRG-9 as the stimulation program has progressed. On 22 August 2013, a step-rate injection test was performed at the site to determine the in-situ stress around the wellbore. This will aid in modeling the fracture propagation in the geothermal reservoir.

A naphthalene sulfonate tracer was injected into the well on 9 September, 2013. So far none of the tracer has been recovered from any of the production wells. Lack of tracer breakthrough only means that the injectate has not physically reached a nearby producer. It is likely that the well is pressure connected to the reservoir but not well enough to provide substantial pressure support. The production wells will continue to be sampled through the high pressure stimulation phase and a new tracer may be injected to determine if the high pressure stimulation connected RRG-9 with one or more of the producing wells.

On 16 October 2013, Sandia National Laboratory's acoustic borehole televiewer surveyed RRG-9 to look for new fractures in the uncased portion of the well (Figure 8). A baseline borehole televiewer survey had been conducted 23 February 2012. The two images will be compared to determine how many if any fractures have been created due to the stimulation program.

Figure 8: Sandia National Labs supervising Tiger Wireline in preparation for conducting a borehole televiewer survey of RRG-9.

4. INJECTION DATA RESULTS

Two techniques that are being used to evaluate the success of the stimulation program are a Modified Hall's technique and an injectivity plot. The Modified Hall's technique involves plotting the cumulative bottomhole pressure, versus the cumulative fluid injection, using Equation 1, Earlougher (1977).

$$\int_0^t p_{tf}\,dt - (p_e - \Delta p_{tw})t = \frac{141.2\mu(p_D+s)}{kh} W_i \tag{1}$$

The bottomhole pressure is estimated using Equation 2, Bourgoyne et al. (1986).

$$p_w = 0.052\rho D + p_0 \tag{2}$$

The changes in the slope can be attributed to changes in permeability, dimensionless pressure, and skin factor around the injection well. The resulting plot will give a straight line with a slope given by Equation 3, Earlougher (1977).

$$m_H = \frac{141.2\mu(p_D+s)}{kh} \tag{3}$$

Figure 9 displays a modified Hall Plot for RRG-9. Permeability is inversely proportional to the slope of the Hall Plot (Equation 3). The slope of the line has continued to decrease as injection has proceeded. The decreasing slope is an indication that the permeability around RRG-9 is increasing. These results are further supported by performing an injectivity index analysis. The injectivity index is obtained by dividing the average daily injection flow rate by the average daily injection pressure. Figure 10 shows that as the stimulation program has progressed, the injectivity index has increased. Higher values mean that more fluid can be injected into the reservoir at a given pressure. This indicates that as fractures are generated or widened new pathways for the fluid are being created, effectively increasing the permeability of the reservoir. The highest value recorded was 0.73 gpm/psi on 22 January, 2014. These two types of analysis support the conclusion that due to the stimulation program permeability at RRG-9 is increasing.

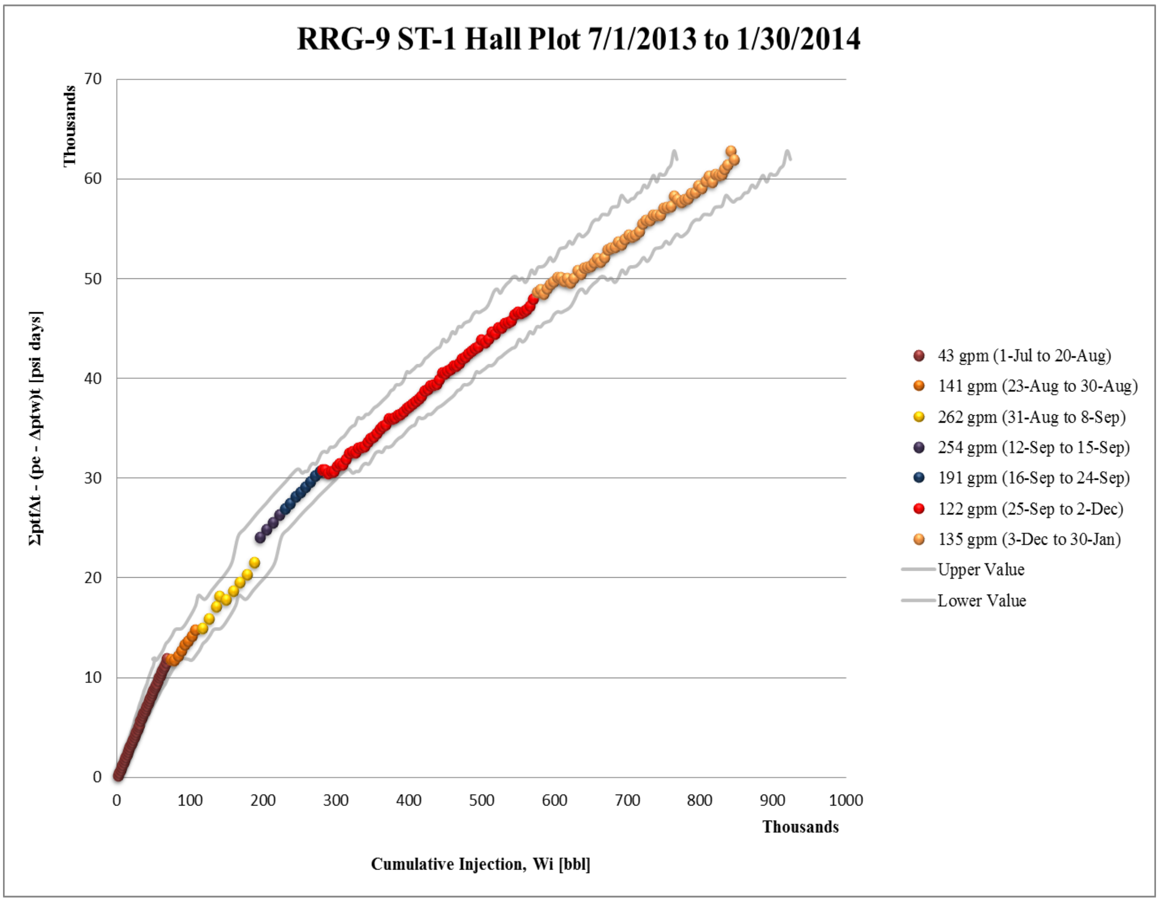

Figure 9: Modified Hall Plot for RRG-9. Warm colors represent the warmer plant injectate, while cooler colors represent the cold well water injection. The light grey lines represent the upper and lower values of each measurement due to a ±10 gpm uncertainty in the flow rate.

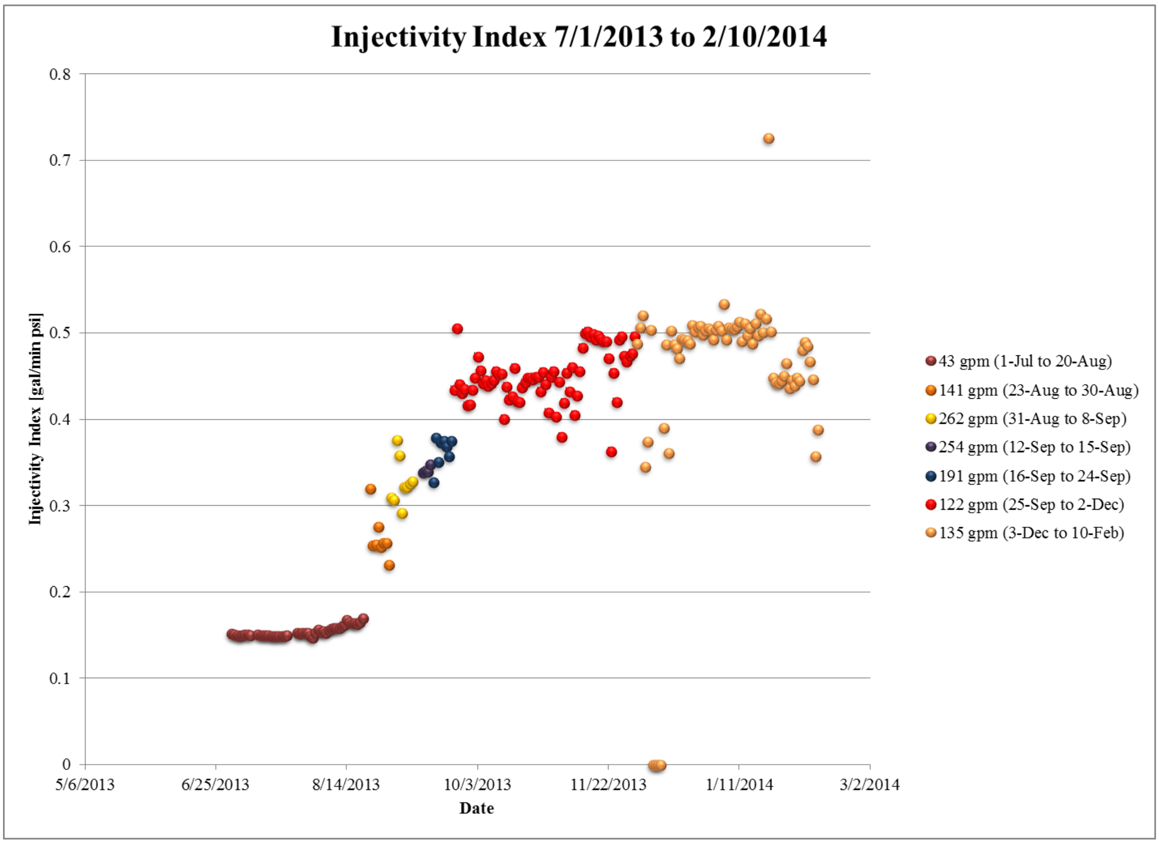

Figure 10: Injectivity Index for RRG-9. Warmer colors represent the warmer plant injectate injection while cooler colors represent the cold well water injection.

6. CONCLUSIONS

RRG-9 has been undergoing injection stimulation almost continuously since 13 June 2013, under various pressure and temperature conditions, primarily at 275 psig and water temperatures between 29 °C and 39 °C. Analysis using both a modified Hall technique and an injectivity index technique indicates that the stimulation program is increasing the permeability of the reservoir around RRG-9. A decreasing slope obtained on the Hall Plot analysis shows an increase in permeability as the stimulation program has progressed. The injectivity index has increased throughout the stimulation program meaning that more fluid is being pumped into the formation at equivalent pressures. These two forms of analysis support the conclusion that increased permeability at the site has been successfully accomplished with the stimulation program. This analysis will continue to be used for monitoring the stimulation program, until the Phase 3 hydraulic stimulation is completed.

ACKNOWLEDGEMENTS

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NOMENCLATURE

D	depth, ft
h	formation thickness, ft
k	permeability, md
m_H	Hall plot slope, psi days/bbl
p_0	surface pressure, psi
p_D	dimensionless pressure
p_e	external pressure, psi
p_{tf}	tubing or wellhead flowing pressure, psi
p_w	bottom-hole pressure, psi
Δp_{tw}	pressure difference between wellhead and bottom hole, psi
s	van Everdingen-Hurst skin factor
t	time, days
W_i	cumulative water injection, bbl
ρ	density, lb/gal
μ	viscosity, cp

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