Mitigation of Calcium Sulfate Scaling in Geothermal Production Wells

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ABSTRACT

Geothermal power generation is growing due to the need for clean renewable energy. The geothermal resources can generate base load power at lowest cost with minimum environmental impact. Fouling mitigation and corrosion control are big challenges in harvesting geothermal energy. Salton Sea resource contains hyper-salinity brines at temperatures approaching 700 °F. At the Hudson Ranch development the majority of the scale is iron-silicate. However, in the high temperature areas of the plant, such as the production gathering system and high pressure separator, the scale can also contain calcium sulfate. Computational modeling was used to predict the precipitation of calcium sulfate based on brine and steam parameters. The paper discusses the impact of scaling in surface equipment and the use of scale inhibitor to prevent scale deposition in the production well as well as in the surface piping between the wellhead and high pressure separator.

Introduction

Fouling of production wells, surface equipment, injection wells and corrosion are big challenges in producing power from the geothermal resources [1]. Silica/Silicate precipitation[2] becomes a problem when the brine cools as it flows up the wellbore, through the surface equipment, and down the rejection well. Due to the presence of elevated sulfate concentration in the Hudson Ranch brine, calcium sulfate is found in the scale formed at high temperatures.

John L Featherstone geothermal power plant (formerly Hudson Ranch I) is located in Salton Sea field, California, US. EnergySource inaugurated the geothermal power plant in March 2012. The Salton Sea field, where the plant is located, has the largest and highest temperature geothermal resources in North America. The John L Featherstone plant is a three-stage flash geothermal plant with an installed capacity of 49.9MW. It is the first new stand-alone geothermal plant in over 20 years in the Salton Sea area. The geothermal power plant provides electricity for approximately 50,000 homes.

The John L Featherstone power plant uses a Crystallizer Reactor Clarifier (CRC) process, which is an advanced method for extracting steam from the geothermal brine while minimizing scaling of the process equipment and injection wells. This process supplies steam to a triple inlet Fuji turbine which achieve higher thermal efficiency compared to earlier designs based on dual inlet turbines (with or without turbo-expanders).

Identification of the Problem

In many parts of the world silica is the critical limiting factor in harvesting maximum thermal energy. Silica precipitation is main cause of fouling of the binary heat exchangers and the injection wells. Many different strategies are deployed for mitigating silica fouling such as injecting the hot brine at moderately high temperatures (with a corresponding decrease in thermal energy recovery), cooling the brines in ponds to promote silica precipitation prior to sending to injection well, controlled precipitation such as CRC process, or retarding the precipitation kinetics by lowering the pH (pH Mod process), and the use of silica inhibitors.

Based on brine chemistry and other thermal parameters of brine at Featherstone Power plant, we have developed well profiles using a computational modeling tool, Geomizer[3]. Geomizer is a very innovative solution for all the geothermal processes based on our unique ability to model any geothermal resource using a modeling tool. Based on the brine and the steam chemistry, we can model the brine chemistry at the bottom of the production well and also calculate resource temperature based on various Geothermometers. This allows us to calculate the potential for mineral precipitation in the production well and recommend the right inhibitor at the right dose and its delivery at the right depth. The inhibitor models are based on kinetic laboratory and field data.

The Geomizer modeling revealed that well 13-1 is not supersaturated with calcium sulfate; however wells HR13-2 and HR13-3 are supersaturated with calcium sulfate (anhydrite). As shown in Figure 1, well HR13-3 has saturation index significantly higher than HR13-2 at any given temperature. The scaling was verified by monitoring scaling at the well head (scale coupons and visual pictures). The output from the Geomizer is shown in the following Figure 1.

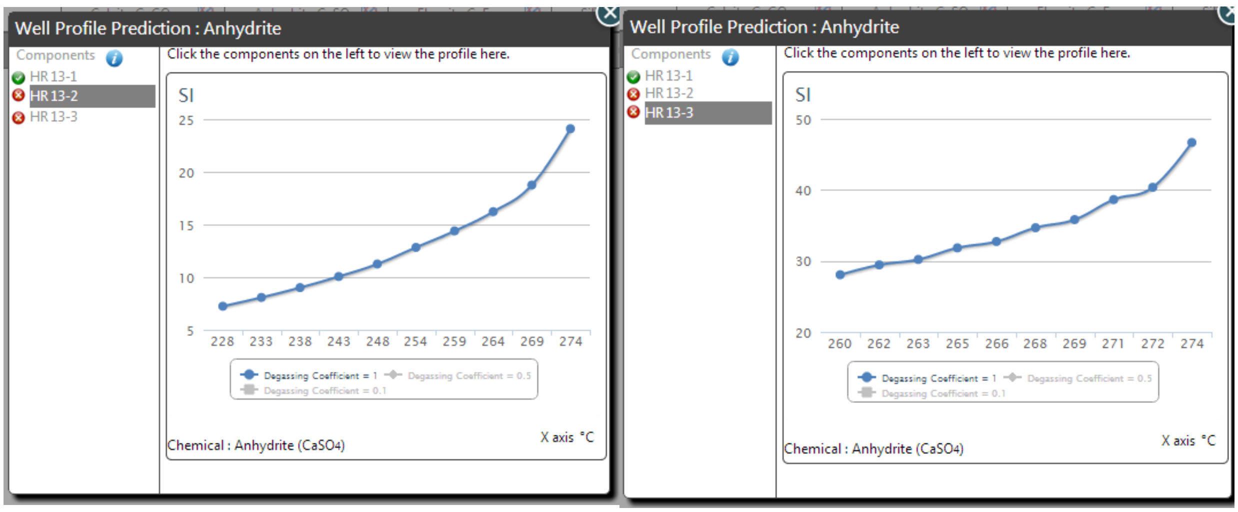

Figure 1. Well profile for Wells HR13-2, and HR13-3.

Scale Coupon Sampling Protocol

A sampling and monitoring program to determine scaling in the brine systems has been developed. The program uses scale coupons (Figures 2 and 3) to measure the tendency of scale to form in the system. The scale coupons have pre-drilled holes on the surface and since scale is most likely to form in cavities, it will therefore form in the smallest size hole. If the pipeline/system brine has a tendency to form scale, the strength of this tendency can be determined by the largest hole that has accumulated scale. The greater the concentration of scaling compounds, the larger the hole size that is likely to accumulate scale. The coupons are inserted using a retractable probe with a packing gland. The coupons are

Figure 2. Strip Corrosion Coupons.

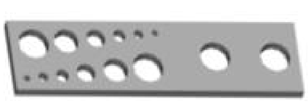

Figure 3. Scale Coupon.

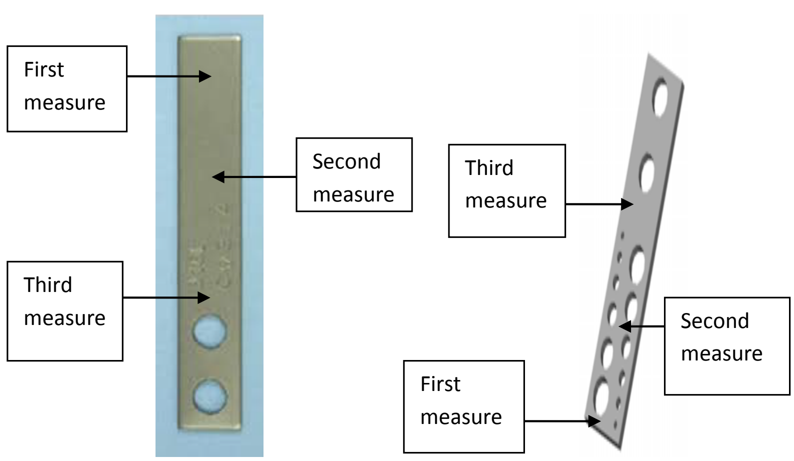

Figure 4. Caliper measurement points.

attached to the holder through either a threaded end or attached with bolts. The probe is 24-36” in length and inserted at least 12” into the pipe so that it is in the main flow of the pipe.

Caliper Readings

Weekly caliper readings at three points (Figure 4) of the coupon surface are taken to measure the thickness and then an average reading of all three is taken. This is done until the scale coupons arrive are inserted and at that time, the strip corrosion coupons are replaced with the scale coupons. Similar protocol is followed for the scale coupons as for the corrosion coupons.

Weight Determination

Weight determination is done on the scale coupon(s) on a monthly basis or as needed. At that time, the old coupons are replaced with new ones.

Monitoring

The recommended and preferred method is to monitor the amount of scaling using the weekly caliper readings and/or visual inspection of the scale coupons. The coupon(s) are replaced on a 30, 60 or 90 day cycle depending on the material/scale collected. Adjustments to the chemical program can also be done using this procedure to optimize the chemical feed to assure scaling is controlled to a minimum and assure pipeline and surface equipment is kept cleaned. Additionally, the differential Pressure (DP) of the production pipeline is also monitored as a measure of scaling.

Table 1. Mixed Calcium Carbonate and Calcium Sulfate inhibition with 5200M, pH 7.5, 250 °C; Ca 250 PPM, SO4 1500 PPM (24 hours incubation time).

Inhibitor	Dose PPM	% Inhibition at various Calcium PPM			
		50	100	500	1000
PAA	5	100	100	60	0
	10	100	100	60	0
PMA	5	100	80	70	0
	10	100	80	60	0
5200M	5	100	100	100	72
	10	100	100	100	89

Development of the Scale Inhibitor

Scale inhibitors are generally organic molecules, which are stable phosphonates, phosphate esters or polycarboxylates. These molecules must withstand the harsh environment of the geothermal brines/process of high salinity, high temperature, and often with non-condensable gasses present. Using an autoclave, we evaluated several scale inhibitors and the results are shown in Table 1.

Under the experimental conditions the brine was supersaturated with respect to both calcium carbonate and calcium sulfate. Based on these results we selected 5200 M (a blend of phosphonate and a copolymer) as it can inhibit both calcium carbonate and calcium sulfate precipitation. Based on the residence time from the beginning of the feed point to the CRC process, the inhibitor dose was adjusted and 5200M was initially fed at 2 PPM and the deposit was monitored at the well head. Slowly the inhibitor was reduced to a point where scaling re-appeared. Inhibitor concentration was brought back to the dose prior to observing the scale.

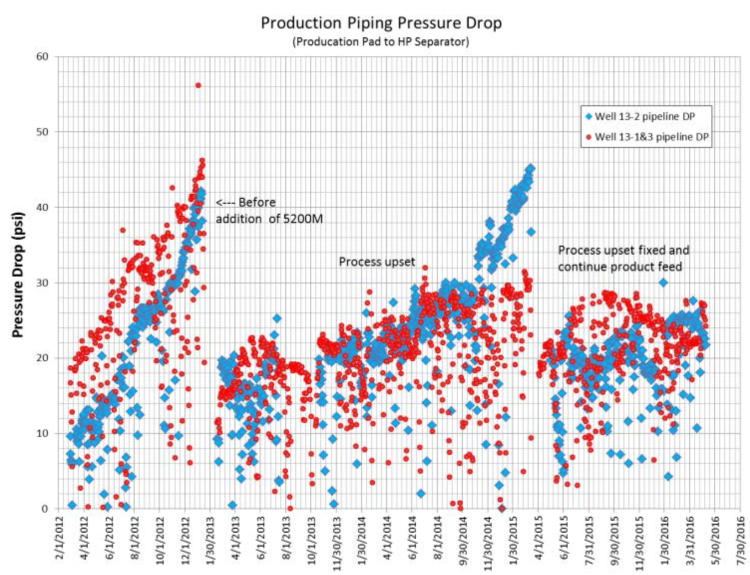

Figure 5. Pipeline DP over time before and after treatment (Nalco 5200M scale inhibitor).

The attached plot, Figure 5 of pipeline DP over time shows a significant reduction in the rate of increased DP with time. The increase in 13-2’s DP was due to the high flow rates from the well required to offset the decline in well 13-3. The impact of deposits on the plant performance, namely power generation, was minimal. There was no generation curtailment since there was excess wellhead pressure that could overcome the increase in pipeline DP. The more likely the critical item that would have forced a plant shutdown before three years was plugging of the vortex clusters in the high pressure separator. This would have increased the carryover from the high pressure separator and at some point limited the brine flow into the plant. The case of the pipeline scale reduction as a result of the treatment starting in 2013 was quite evident based on the pressure drop criteria shown in Figure 5.

The reduced rate of scale buildup based both visual inspection and coupon data and ease of removal of the deposit suggest the $CaSO_4$ was being inhibited both through threshold inhibition and crystal modification. The significantly lower overall scaling rate suggests the scale inhibitor is partially effective on the iron silicate scale in addition to calcium sulfate. The iron silicate deposit was further reduced by the addition of another silica inhibitor GEO980 in addition to 5200M. The morphology and thickness of the scale is shown in Figure 6 (prior to feeding the scale inhibitor) and Figure 7 after the scale inhibitor was fed at the wells. Both Figures (6 and 7) represent the same location. On opening the high pressure separator, at approximately the one year anniversary of the plant startup, a 2.5″ layer of hard scale was found (Figure 6). Visual inspection of the scale revealed thin white crystals within the black iron silicate scale that is normally found. XRF analysis of the scale showed 37% $CaSO_4$ which is in-line with the physical appearance of the scale. This scale posed two problems. First the amount of scale in the production header and the vortex clusters in the high pressure separator would limit the turnaround periods from the planned 3 years to less than two years. Secondly, the $CaSO_4$ fibers form a composite material, much like fiberglass, that was very difficult to remove.

Figure 6. High Pressure steam pipe 2013 Prior to the Scale inhibitor treatment.

Figure 7. High Pressure steam pipe 2015 after the Scale inhibitor treatment.

On opening the high pressure separator, approximately two years after the 2013 inspection, a thin layer of brittle black iron silicate scale was found (Figure 7).

As found in the past, thermal shock causes much of this scale to fracture and fall off of the alloy piping. Chemical analysis of the scale showed very low levels of sulfate (31 ppm SO_4). Based on the significant reduction in scale both volume and thickness and the dispersant properties of the inhibitor in reducing the amount of iron silica scale that is forming in the production line and high pressure separator the scale inhibitor program is deemed successful. Overall, the inhibitor has reduced the scaling rate such that 3 year plant turnarounds are possible and that is significant payback on two years turnaround without the inhibitor. The cost savings of the longer turnarounds, combined with the much easier cleanout of the anhydrite free iron silica scale, is significant.

Conclusions

Overall, the Nalco 5200M inhibitor has reduced the scaling rate, in brines at the Featherstone geothermal facility, such that 3 year plant turnarounds are possible. The cost savings of the longer turnarounds combined with the much easier cleanout of the anhydrite free iron silica scale is significant. There is a significant reduction in the rate of increase in pipeline DP with time. The inhibitor not only provided complete inhibition of calcium sulfate anhydrite but also reduced the rate of iron silicate deposition.

References:

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