

Acid Stimulation of Kawerau Injection Well KA44 Using Hydrofluoric Acid and Formic Acid

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ABSTRACT

Injection well KA44 at the Kawerau Geothermal Field was acidised with 10% HCOOH (Formic Acid) / 5% HF (Hydrofluoric Acid) in April 2019. This work, along with a previous acid stimulation of injection well PK4a in 2017, was conducted to improve the well's injection capacity while also providing information to a wider investigation to address silica management at Mercury's geothermal fields. Several of Mercury's geothermal fields operate with silica saturation indices in excess of 1.7, as described in Addison et al. (2015). Despite the use of various plant designs to reduce the risk of silica polymerization and deposition, injection well decline continues to be an issue.

KA44 was selected as a candidate well for acid stimulation, as it is shown through reactive modelling and laboratory testing that the injection decline is a result of silica scaling in the near wellbore formation. KA44 was acidised previously in 2010 using 10% HCl (Hydrochloric acid) / 5% HF, however the initial improvement in injectivity was short lived.

The 2019 KA44 acidisation program was optimised based on lessons learned from the previous stimulation in 2010 and from the acid stimulation of PK4a in 2017 in order to improve the chance of success. The results of this acid stimulation of KA44 are compared against the first acid stimulation of this well in 2010, as well as the results of the acid stimulation of PK4a in 2017.

1. INTRODUCTION

Injection well KA44 is located at the Kawerau Geothermal Field, Bay of Plenty, New Zealand. It is known to suffer from injection decline while operating on brine from the Kawerau Geothermal Limited (KGL) power plant. When it was drilled in 2007, the initial injection capacity of KA44 was in excess of 1000 t/h and had since declined to ~215 t/h by early 2019. Both geochemical modelling and laboratory fluid-rock interaction testing supports the decline being a result of silica scaling in the near wellbore formation.

The KGL power plant produces geothermal brine with a silica saturation index of >1.7 requiring the employment of silica management processes. At the KGL plant, sulfuric acid is added to the geothermal brine in order to inhibit the polymerization of silica. While this technique successfully controls silica at the plant and in the brine handling systems, injectivity decline in the field continues to be an issue. Laboratory studies showed that the acidified brine reacts with the calcite rich greywacke reservoir rock and is neutralized, causing silica to precipitate in the near wellbore formation (Siega et al., 2019).

KA44 was previously acidized in 2010. Although the initial improvement in injectivity was short lived, it showed that recovery could be achieved, and potentially maintained using the acid stimulation method. High temperature casing caliper (HTCC) logs conducted in KA44 following the acid stimulation in 2010 and again in 2013 showed that the casing was in good condition and that the initial acid stimulation had no adverse effects on the well casing.

2. KA44 ACIDISING 2010

KA44 was acidized in 2010 using a Coiled Tubing Unit (CTU) to deliver mud acid (10% HCL / 5% HF) with a 10% HCL pre-flush and a water over-flush. Five target permeable zones of varying thicknesses were treated, as shown in Figure 1. The details of this acid stimulation are described in Lim et al 2011.

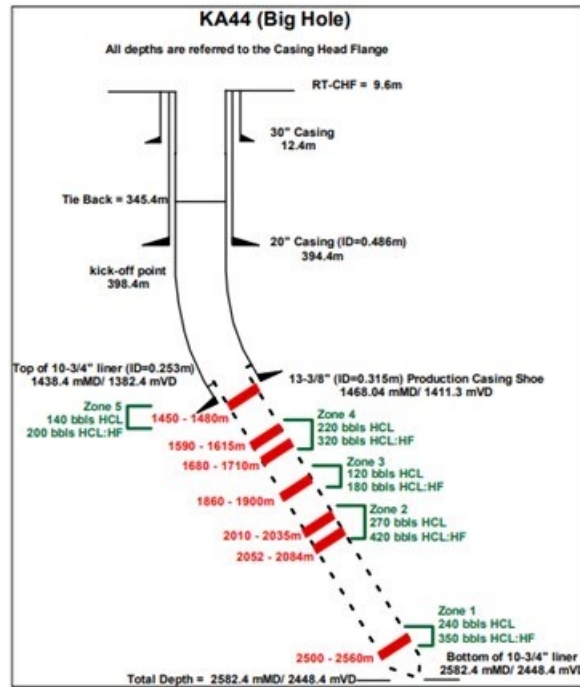


Figure 1: Acid stimulation target zones (red) and amount of acid used to treat each zone in 2010 (green) (Lim et al., 2011).

3. PK4A ACIDISING 2017

PK4a was acidized in 2017 utilizing a CTU to deliver a mud acid mixture of 10% HCl/ 5% HF. Based on a risk assessment and wellbore modelling studies, a top-down approach was chosen to target the zones shown in Figure 2.

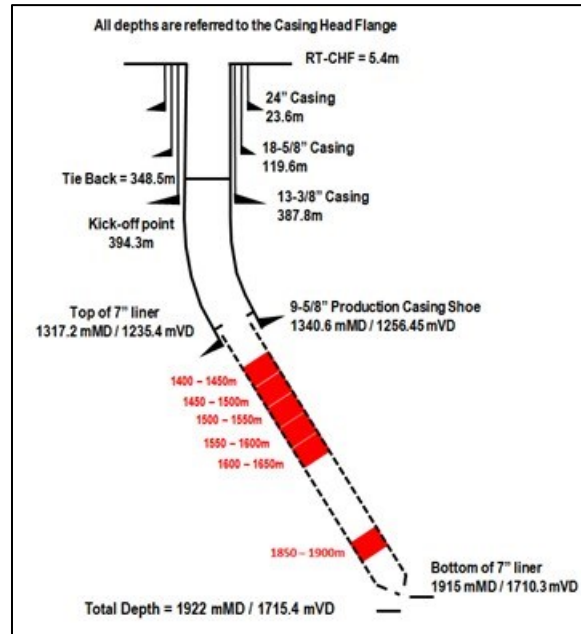


Figure 2: 2017 acid stimulation target zones in PK4a (Coutts et al., 2018)

The 2017 acid stimulation of PK4a successfully increased the total injectivity from 8.1 t/h/bar pre-acidising to 26 t/h/bar post-acidising and a reduction of skin damage from +3 to +0.51 post-acidising.

Immediately after acidising the well, the injection capacity was increased by ~90% as reported by Coutts et al. (2018). Although injection decline continued post-acidising, the injection capacity was still 10% above the pre-acidising capacity after 12 months. This was a significant improvement compared to the 2010 acidising where the increase in capacity only lasted two months.

From the acidising of KA44 and PK4a it was concluded that using a CTU to target feedzones is challenging due to a lack of cost-effective options for fluid diversion and the use of bull-head stimulation may provide similar level of performance improvement but at a significantly lower cost.

4. KA44 ACIDISING 2019

4.1 Acid Delivery Strategy and Benefits

Two options were considered for applying the acid down hole; that is, at specific depths for treatment via coil tubing, or all chemical pumped from the surface through the wellhead or side valve (bullhead application). Based on the experiences and results from the acid stimulation campaign in 2010 and the 2017 acid stimulation of PK4a which both utilized coil tubing, it was decided to utilize surface pumping (bullhead application) for KA44's acidising in 2019.

While the use of a bullhead application removed the ability to target specific feed-zones in the well, there are several benefits to the bullhead technique that the project team aimed to realise, as outlined below.

4.1.1 Increased Pump Rate

The application of the acid through a bullhead process enabled a significantly higher flowrate of the acid to be achieved compared to the use of coiled tubing. While the use of coiled tubing (2" diameter) typically restricts flow rates to approximately 30m³/hr in Mercury's wells, the bullhead application enabled flow rates in excess of 100m³/hr if suitable pumping and mixing equipment was used. For KA44 a pump rate of 80m³/hr was selected to balance the benefits of a higher pump rate with the contact time required for the acid to react with the target formation.

The benefits the increased pumping rate included a reduction in the likelihood of hot inflows into the well during the application of the acid mixture. This reduced the risk of corrosion to the well tubulars due to both the lower likelihood of exceeding the corrosion inhibitor temperature rating, and the lower contact time between the acid mixture and the well tubulars.

The higher pumping rate was also expected to improve feedzone coverage, as the higher flows and well pressure would enable the acid mixture to penetrate more feedzones, including the shallower feedzones in the well. During previous acid stimulations with a CTU it was suspected that the acid mixture was mostly reporting to the bottom of the well due to its increased density over the reservoir fluid.

The increased pumping rate also reduced the pumping time required to apply the acid mixture to the well. This reduced both the equipment time required and the time taken to complete the work – resulting in both equipment and labor cost savings.

4.1.2 Improved Simplicity

The bullhead application enabled improved simplicity of both the equipment setup and process of acid application. With the absence of a CTU, there was also no requirement for a high pressure pumping unit, or a need for a crane during normal operation. This resulted in a lower equipment footprint, reduced preparation works and a faster set-up and rig-down of the equipment – further reducing the time taken to undertake the acid stimulation process.

As individual feed-zones were not able to be targeted, the pumping schedule was also significantly simplified – with a single pre-flush, main-flush and post-flush required for the entire well, instead of for each targeted feed-zone. This also significantly reduced the pumping time required for the stimulation (no coil moves between feed-zones) along with the higher pump rate.

4.1.3 No Downhole Equipment

As the bullhead process is all undertaken from the surface, there is no need to place equipment inside the well. This had the benefit of eliminating the risk of losing tools down the well, or getting them stuck, either of which could result in costly delays.

Another benefit of not needing to place tools into the well was the retention of all the well primary barriers. The master valve and side valves on the well head were able to remain in place and operable throughout the acid stimulation process.

4.1.4 Reduced Cost

Cost is one of the most significant factors in determining whether an acid stimulation will provide value in increasing the productivity or injectivity of a well. The utilization of the bullhead process with the benefits listed above significantly reduced the cost of the acid stimulation of well KA44 when compared to a similar acid stimulation utilising coil tubing (PK4a). In this case, the change in program resulted in an approximately 50% reduction in the cost of the acid stimulation.

4.2 Chemical Selection

Mixtures of hydrofluoric acid are routinely used for the chemical removal of silica deposits. The possibility of using a sodium hydroxide solution for silica removal was considered, however it was ruled out due to the heat and contact time estimated to be required for a successful treatment.

A treatment formulation of 5%HF/10%HCOOH (formic acid) was selected for KA44. This selection was based on successful solubility testing and acid stimulations with traditional mud acid (10%HCl/5%HF), while logistical challenges and considerations resulted in the substitution of formic acid in place of hydrochloric acid. The application of the acid mixture was preceded by a pre-flush with 10%

HCOOH, to ensure the removal of any remaining carbonate material that could form insoluble precipitates with HF (e.g. CaF₂). The application of the mud acid would also be followed with a post-flush of 5% HCOOH to maintain acid strength in the treatment zone to minimise the precipitation of reaction products. The post treatment acid flush would then be followed with a condensate flush to remove all of the acid mixtures away from the well bore and near wellbore area.

The application rates of the pre-flush, main flush and post-flush stages were selected as a result of a literature review, and discussions with other geothermal operators of the rates typically used in geothermal applications for the successful removal of silica in injection wells (e.g. Flores-Armenta and Ramirez-Montes, 2010) and previous acid stimulations within the Kawerau geothermal field.

The application rates selected are shown in Table 1 below and are based on a total feed-zone thickness of 300 meters:

Table 1: Acid Application Rates

Stage	Formulation	Volume (m ³ for well)
Pre-flush	10%HCOOH	190
Main-flush	5%HF/10% HCOOH	280
Post-flush	5% HCOOH	50
Final-flush	Condensate	>200

The use of formic acid instead of hydrochloric acid resulted in a significant reduction in the volume of chemicals required for the acid stimulation as the formic acid could be supplied at 84% concentration compared to 32% for hydrochloric acid. This resulted in approximately half the volume of formic acid, compared to the volume of hydrochloric acid that would have been required, reducing the chemical bunding and space requirements for acid storage. Another benefit of using formic acid was the reduced corrosivity of the resulting acid mixtures compared with hydrochloric acid mixtures, although this benefit is largely negated with the use of appropriate corrosion inhibitors. At the time of the acid selection it was unknown if the slower reaction rate of formic acid in the formation compared to hydrochloric acid would impact the effectiveness of the acid stimulation.

4.2.1 Corrosion Inhibition

The corrosion inhibition system for KA44 was designed to achieve acceptable corrosion rates (<0.05lb/ft²) at temperatures up to 90°C. This required the use of a corrosion inhibitor, however intensifiers were not required due to the design temperature. The well was swapped from brine service (130°C) to condensate service (40°C) four days prior to the acid stimulation to both remove brine from the well bore area and to cool the well to ensure a suitable temperature for acidising.

4.3 Well Temperature

The well temperature control philosophy for well KA44 was changed from that used on well PK4a in 2017. For well KA44 the well was not in condensate service for as long prior to the acid stimulation, with the condensate service time being determined from well bore modelling to achieve a well bore temperature of less than 80°C. Due to the higher flow rate being used for KA44, and the subsequent reduction in the risk of a hot inflow, further cooling below 80°C was not deemed necessary; while the shorter contact time between the acid mixture and the near well bore formation (due to the faster pumping rate) required a warm temperature to ensure a sufficient reaction rate.

At the completion of the acid stimulation, once the acid mixture had been displaced to the formation, the well was allowed to heat up for several days prior to being returned to brine service. This step was taken to reduce the likelihood of hot, SSI~2 brine, being pumped into a cooled well bore where the brine would be cooled and the SSI increased significantly above 2. The addition of this step was a result of the rapid initial decline in capacity observed in well PK4a when it was returned to service post acid stimulation in 2017. It was expected that this step would result in a lower initial post stimulation injection capacity (due to reduced thermal stimulation), but that the decline in well capacity on the return to service would be less severe, as the risk of scaling and deposition would be reduced.

5 RESULTS

5.1 Velocity Profile Comparison

As shown in the fluid velocity profile in Figure 3, the acid stimulation of KA44 in 2019 appears to not have preferentially stimulated any of the pre-existing loss zones; rather there is an overall stimulation in all the loss zones. In pre- and post-acidising injection profiles shown, over 40% is loss over the broad loss zone from 2102m MD to 2186m MD (midpoint 2146 m MD), ~25% in the top loss zone at 1475 m MD, ~10-12% at loss zones 1973m MD and 2070m MD while the rest of the fluid is loss over the deeper zones past 2200 m MD.

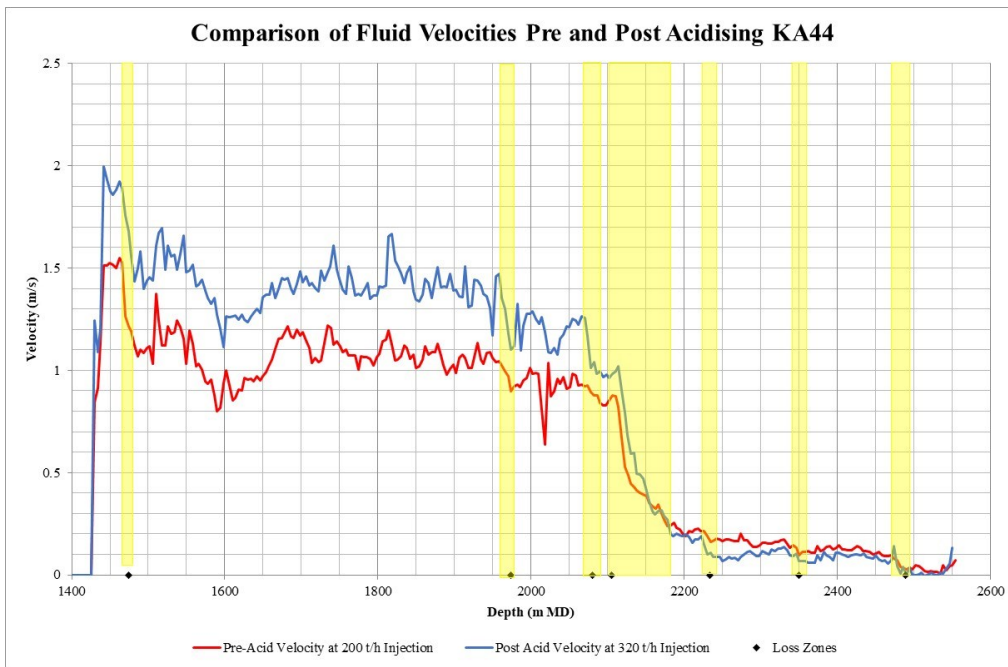


Figure 3. Comparison of velocity profile of KA44 during hot brine injection along the perforated liner section showing the pre-acid and the post-acid profiles. The interpreted loss zones are in boxes.

5.2 Injectivity Index (II) Comparison

The original completion injectivity index (II) of KA44 was measured to be 97 t/h/bar in 2009. However, due to silica scaling near wellbore formation, the II had declined to 6.2 t/h/bar in 2019 despite being acidized in 2010.

After acidising in 2019, the II of KA44 increased to 10.2 t/hr/bar under hot brine injection, as shown in Figure 4. This indicates improved capacity and reduced restriction to flow, requiring generally lower wellbore pressures to inject a similar hot brine flow rate.

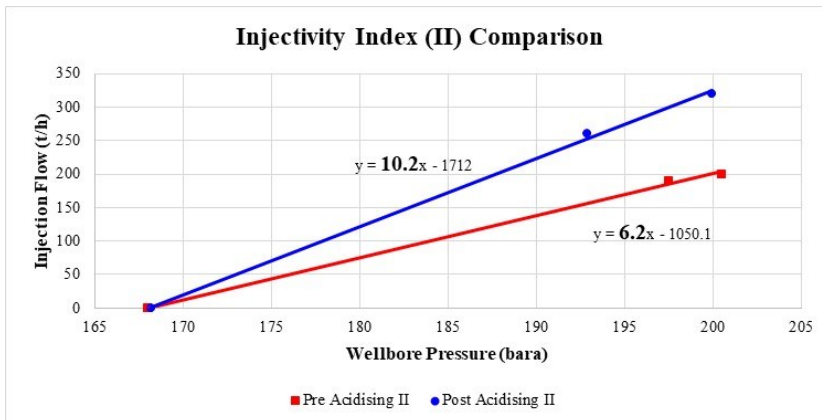


Figure 4. KA44 injectivity index at pre-acid and post-acid multi-rate injectivity tests using similar injection rates.

5.3 Analysis of Feed Zone Contribution and Total Injectivity Index Over Time

Table 2 shows an analysis of changes to permeable zone contributions and total injectivity index in KA44 over time. The total injectivity measured at completion was 97 t/h/bar, however, the II had decreased by more than half to 45 t/h/bar in 2009 and subsequently reduced further to 25 t/h/bar in 2010 in a pre-acidising PTS. Analysis of feedzone contributions in that time period showed that most of the fluid injected was lost over the feedzone at 2110m – 2190m MD while the deeper feedzones beyond 2200m MD had minimal contribution. The acidizing intervention undertaken in 2010 managed to increase the injectivity to 50 t/h/bar and the feedzone at 2350m MD was recovered. Lim et al. (2011) concluded that the acid placements in the 2010 acidising campaign were unsuccessful as once the main bottom zones becomes unblocked, a preferential pathway opens for acid to exit the well.

Between the post-acidizing in 2010 to pre-acidising in 2019, the injectivity index had decreased from 50 t/h/bar to 6 t/h/bar. Feedzone contributions also changed significantly. The inflows detected in 2010 are now accepting fluid while deeper feedzones that previously

contributed over 20% of the total II are now minor feedzones. The acidizing in 2019 did not preferentially stimulate any feedzones as contributions post-acidising remained similar to the pre-acidising baseline.

Table 2: KA44 Feedzone analysis showing changes to contributions and injectivity index over time

Feedzone Depth (m MD)	2007 Completion	2009 Brine Injection	2010 Pre-acidising	2010 Post-acidising	2015 Injection	2019 Pre-acidising	2019 Post-acidising
1450-1480	Inflow	Inflow	Inflow	Inflow	24%	27%	29%
1680-1710	Inflow	14%	Inflow	Inflow	--	--	--
1860-1890	Inflow	13%	--	--	17%	--	--
1975-2005	Inflow	7%	--	--	10%	8%	12%
2008-2080	Inflow	12%	--	--	--	13%	14%
2110-2190	28%	43%	72%	49%	45%	48%	42%
2295-2335	24%	--	--	--	--	3%	2%
2350	--	--	14%	28%	2%	2%	2%
2489-bottom	48%	11%	14%	23%	3%	3%	1%
Total Injectivity (t/h/bar)	97	45	25	50	12	6	10

6. DISCUSSION

International case studies of HF acid stimulation to remove silica scale have demonstrated significant improvements in injection capacity. For example, Flores-Armenta and Ramirez-Montes (2010) reported an average improvement of >78% across acid stimulation on four injection wells at Las Tres Virgenes and Los Azurfres geothermal fields in Mexico. In the Philippines, Buñing et al., (1995) and Malate et al., (1998) showed >100% improvement in injection capacity and up to 900% in one instance. This is consistent with the experience of acid stimulation in Kawerau, where the acidizing campaign in 2010 across two injection wells showed an average improvement of >85% in total injectivity index as reported by Lim et al. (2010) and 90% improvement in the well capacity acidized in 2017 as reported by Coutts et al., (2017). However, there is variability in how long these improvements in injection capacity are maintained following acid treatment.

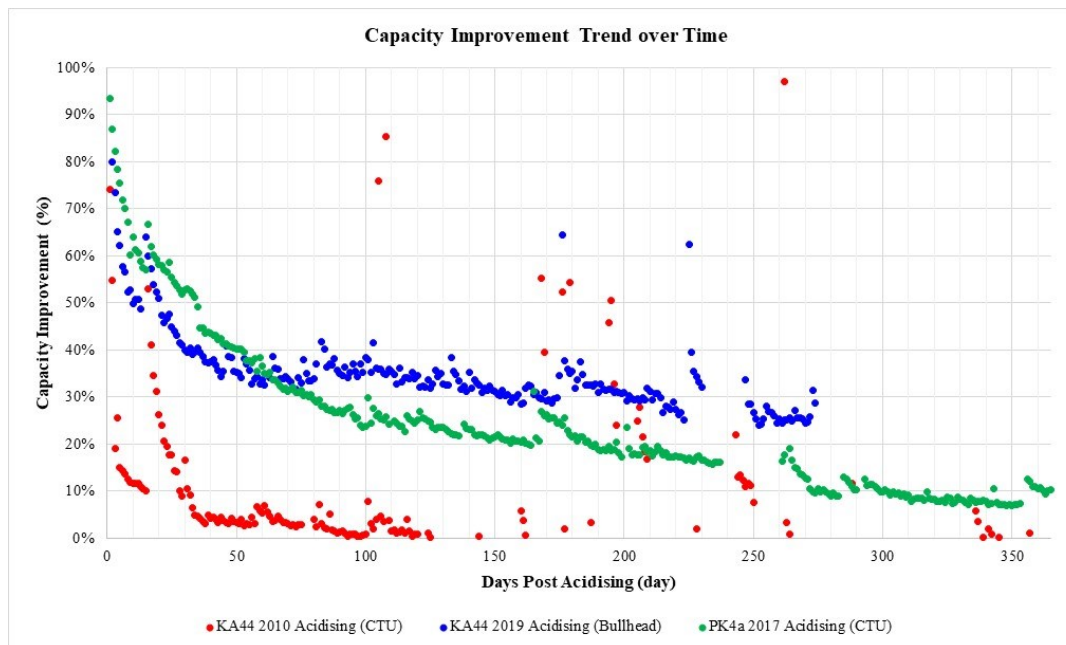


Figure 5. Comparison of the decline in capacity gain over time of KA44 2010 acidising with CTU, KA44 bullhead acidizing and PK4a acidizing with CTU.

Figure 5 shows that the initial capacity improvement in KA44 post acidizing in 2019 was 90%, however, there was rapid decline in the first 30 days post acidizing before the decline rate stabilized to a more typical long-term decline rate. At 275 days post-acidizing, the capacity of KA44 is still >25% more than the pre-acidizing capacity. This is a significant improvement from the KA44 acidizing intervention done with CTU in 2010 where the improvement only lasted less than 50 days. The 2017 acidizing of PK4a had an initial higher capacity gain however, after a comparable time (275 days), the capacity gain was only 10% of the pre-acidizing capacity indicating that overall decline in capacity improvement of PK4a was higher than KA44.

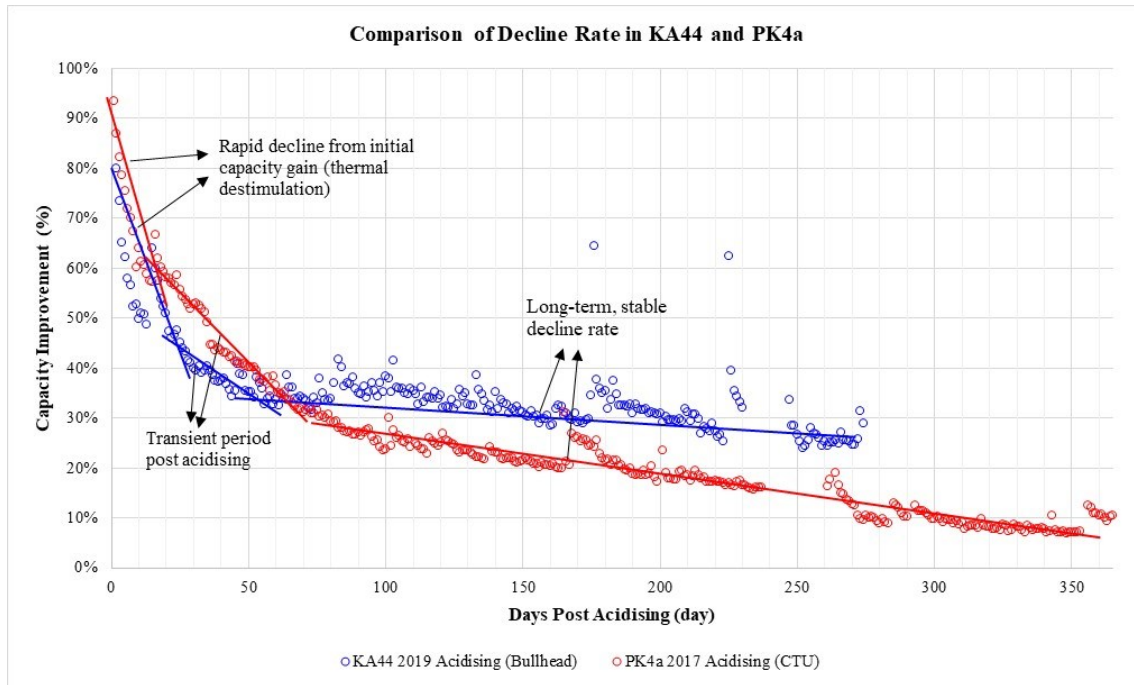


Figure 6: Comparison of decline rate in PK4a (2017 acidizing done with CTU) and KA44 (2019 bullhead acidizing)

Figure 6 shows that both KA44 and PK4a displayed similar trends in decline post-acidizing where a rapid decline from the initial capacity is observed for the first 10-15 days and this has been attributed to thermal destimulation (Coutts et al., 2018). As part of the acidising program, the wells are injected with condensate (40°C) for a period of time prior, and this thermally stimulates the well and partially contributes to the initial gain in capacity. KA44 was allowed to heat up for three days prior to the reintroduction of hot injection fluid (130°C) to ensure that nearby wellbore formation temperature is as close to the temperature of the hot injection fluid as possible. The rapid decline is followed by a transient period of up to 75 days where decline rate is higher than the stable decline rate before returning to a long-term typical decline rate that was observed pre-acidising.

Using a CTU to spot-apply acid has advantages and has been successful in other scale blockage removal but it has been underwhelming in regards to stimulating specific target feed zone depths. Our experience in 2010 and in the 2017-2019 campaign has shown that targeting feed zones for acid stimulation is a challenging exercise because of the lack of cost-effective options for fluid diversion. If cost effective fluid diversion cannot be achieved, the use of bullhead acid stimulation appears to be capable of providing a similar level of performance improvement to coil acidising, but at a significantly lower cost.

6. CONCLUSION

The acid stimulation of injection well KA44 has successfully increased the capacity of the well, while the improved capacity has deteriorated over time, it has retained a higher capacity gain than previous injection wells stimulated in the Kawerau geothermal field. The application of the bullhead technique significantly reduced the cost of the acid stimulation – with the cost of the 2017 KA44 acid stimulation being approximately half of the cost of the 2017 stimulation of PK4a, while achieving similar overall results. These results indicate that the acid stimulation of injection wells can be a cost effective method of maintaining injection capacity for Mercury.

The use of formic acid instead of hydrochloric acid enabled the acid stimulation team to minimise the volume of chemicals on the site. This enabled simplified chemical logistics and improved flexibility while also reducing the risk of corrosion to the well tubulars in the event of a corrosion inhibitor failure.

The addition of a well heating step, prior to returning the well the brine service is suspected to have been beneficial for the long term well performance, and this step will be added to future acid stimulation programs at Mercury.

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