Calcium Carbonate Scale Inhibition Program on Two-Phase Geothermal Well in Indonesia

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***Abstract*—The formation of calcium carbonate (calcite) is a major scaling problem that occurs in geothermal wells around the world, leading to a quick decline in well output, reduced power plant production, increased maintenance frequency and operating costs. More than 80% of geothermal operation has calcium carbonate scale. Several methods can be used to prevent calcite scale and to rehabilitate affected production wells. At the Solenis (previously known as NEUCHEMIE a Solenis company) customer's geothermal field, the scale prevention program was conducted by continuous online injection of the NEU GUARD PW920 scale dispersant until it reached the total well depth. The scale dispersant was injected through capillary tubing with a special dosing pump using a method called downhole scale inhibition (DSI). During the project trial period, we took water samples and analyzed several minerals' parameters to detect the extent of the effect of the scale dispersant injection through the capillary tubing. Using the data from the plant trial, the water analyses, and the scale coupon monitoring program, we determined that an optimum dosage of scale dispersant is 8 ppm. Throughout the implementation process, the total removed calcium was 479 kg/day or, stated another way, over an approximately 3-months (84-day) period as much as 40.24 tons of potential calcite was removed from the well.**

***Keywords*—Calcite, Calcium Carbonate scale, Downhole Scale Inhibition, Scale Prevention, Scale Inhibition, Chemical Treatment, Two-Phase Geothermal Well, Indonesian Geothermal**

I. INTRODUCTION

Calcite can be formed because of hydrolysis, boiling of geothermal fluids, and heating of colder environmental geothermal fluids. In a boiling environment, layered calcite precipitates in open areas upon loss of carbon dioxide, mostly with pH-controlling carbonate species [1].

Calcium carbonate scales (in the crystalline forms of calcite or aragonite) are common in wells with reservoir temperatures of 140–240 °C and are primarily found at the depth where the water starts to boil in the well [2].

According to the research, calcite incrustation is quite common in the range of 140–280 °C. For example, the Ribeira Grande geothermal field, with an estimated temperature of 235–245 °C, is in this category. In these types of reservoirs, geothermal fluids are often saturated with calcite and become saturated inside the wells. After boiling and flashing to lower temperatures, the aqueous Carbon dioxide is reduced as it turns into the gas phase. Therefore, the Carbon dioxide leaving as gas phase increases the pH and carbonate concentration of the water phase. Thus, the increase in calcite concentration results in a transition of the calcite solubility phase from a saturated to a supersaturated state and causes precipitation [3].

The chemical composition of the geothermal fluid has a significant effect on the formation of calcite deposits in boreholes. Chemical inhibition is the best option to avoid the expensive work-overs associated with reaming or chemically cleaning of wells and out of service periods [3].

One of the most common techniques for controlling carbonate scaling involves the use of chemical additives (crystal growth or scale inhibitors, anti scalant). These substances are usually moderately large molecules that are readily adsorbed on the growth-active sites of the crystal surfaces, thus retarding nucleation and crystal growth, and distorting the crystal structure of the scale. The various inhibitors are considered to act according to one (and usually more than one) of the following main mechanisms of interference with crystal growth:

1. *Threshold effect*: the inhibitor acts by retarding salt precipitation.
2. *Crystal distortion effect*: the inhibitor interferes with crystal growth by producing an irregular structure (usually rounded surfaces) with poor scaling potential.
3. *Dispersion:* inducing a charge on the crystal surface results in the repulsion between neighboring crystals.
4. *Sequestration or chelation*: the binding with certain cations (Fe, Mg, etc.) to form soluble complexes [4].

Fig. 1 shows the main scale inhibition system that is used for chemical injection in the wells. This system's equipment includes a metering pump for continuous injection of a low-dose scale dispersant (up to 59 bar); a lubricator set, consisting of a 5-meter, 3-inch steel pipe with a stuffing box mounted on the top and a ram BOP (blowout preventer valve) connected on the bottom. Lubricant allows the installation of the downhole equipment in the well under pressure. Downhole equipment consists of an inhibitor injection chamber (high pressure valve) and a sinker rod. Nickel–iron–chrome capillary tubing is used (0.25 in outer diameter (OD)) to transport the inhibitor from the surface to the downhole equipment [3].

Calcite inhibition performance is monitored by several useful chemical and physical parameters, of which the wellhead pressure, discharge enthalpy and total flow rate are important. Potential of hydrogen (pH) levels and calcium and bicarbonate content are often measured because changes in the composition of the chemical species involved in the formation of calcium carbonate are significant. In addition, dynamic pressure-temperature (PT) records and production tests are performed periodically to keep production data up to date [1].

Well-A is one of the most important wells in the customer’s field, which was completed at the end of 2021. The well, with high enthalpy and high flow capacity, produces in two phases as steam and brine. This well, which contributes 22 MW to the power plant, must be reliably operated because it contributes significant profits to the customer.

When Well-A was put into production, the customer implemented a scale mitigation program to minimize scale-related production losses from this well. We, as experts in this field, were appointed as the preferred partner to provide innovative solutions to the current scale and corrosion issue at the customer’s field. We collected the well chemistry information from the customer and chose the best scale dispersant to solve the problem. Also, we used the best capillary tubing metallurgy for an aqueous, corrosive environment. At the end, we applied our downhole scale inhibitor (DSI program at Well-A and succeeded in preventing scale formation in the well. We started implementing the project on 18 January 2022 and continued through 15 April 2022.

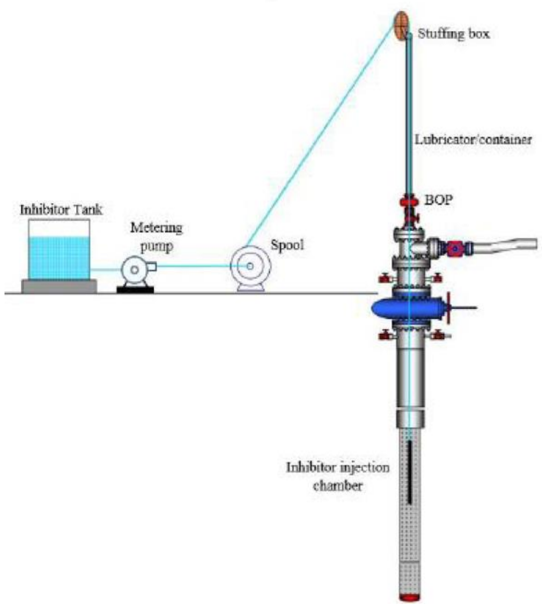


Fig. 1. DSI system installed in production wells [3].

While monitoring the performance of the DSI program, we noted and investigated signs of corrosion at the well. We reported the corrosive tendency of Well-A and several other observations that provided evidence of active corrosion to our customer because this corrosion could impair future well production and result in costly maintenance.

II. Preparation for Downhole Scale Inhibition (DSI) – Data Collection and Analysis

Before we implemented the DSI trial project, we collected from the customer information regarding the chemical and physical data of Well-A. We conducted an extensive and wide-ranging study to determine the suitability of the geothermal well for the implementation of a downhole chemical inhibition system.

By using the two-phase flowing data, the flowing pressure-temperature-spinner (PTS) survey data and the casing tally, we determined the steam zone, transition zone and liquid zone for the calculation of the injection depth and weight of the sinker bar to be used. That calculation was the most important safety aspect of the operation.

After evaluating the non-condensable gas analysis and brine water analysis data, we decided which scale dispersant to use in the well. In addition, metallurgical requirements of the capillary tubing and sinker bar were determined.

The preliminary data collection about the chemical, physical and historical information of the well helped us provide the best operating conditions throughout the project.

A. Two-Phase Flowing Data

In 2021, Well-A, shown in Fig. 2, started to produce approximately 65 kg/s total mass flow, with a flowing enthalpy of approximately 2117 kJ/kg and a wellhead steam fraction of about 58%. According to the information provided by the customer, Well-A produced liquid from the deepest three feed zones and the well was then fed with steam from two shallower feed zones. The ground elevation of Well-A is 1720 meters above sea level.

Depth m MD	Elev mASL	TMF Cont kg/s	Steam Cont kg/s	Pwf bara	Twf degC	Steam Cont	TMF Contribution	Preservoir bara	Hres kJ/kg	dP bar	PI kg/s/bar
1140	623	45	45.0	31	235	92%	69%	50.7	2800	20	2.250
1509	272	1	0.6	39	248	1%	2%	63	2000	24	0.041
1680	103	1	0.1	44	255	0%	2%	75	1100	31	0.032
2001	-217	3	0.4	67	255	1%	5%	99	1100	31	0.096
2124	-339	15	2.8	77	273	6%	23%	108	1180	31	0.478
	Total	65						Total			2.898

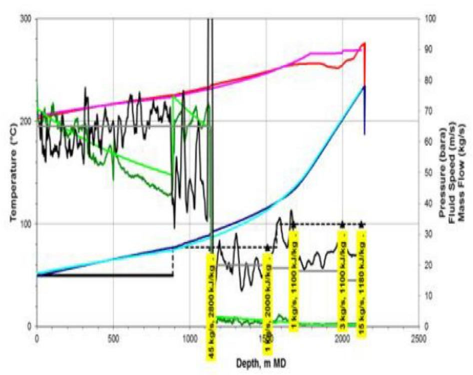


Fig. 2. Two-phase flow characteristics of Well-A.

B. PTS Flowing Data

Flowing pressure survey indicates that liquid flow starting from the deepest depth flashes at approximately 1700 mMD and produces two-phase flow at the surface. Static and flowing temperature surveys, shown in Fig. 3 and Fig. 4, demonstrate that the maximum flowing temperature is the flashing point depth, which is 252 °C and reduces to 190 °C at the surface. Because of the static and flowing PT surveys, we decided to implement the chemical injection within the liquid zone, under 1900 mMD, and the customer agreed. Pressure and temperature values at that depth were used for chemical durability tests in the laboratory to determine the best scale dispersant. Also, these values were used for the design of the dosing systems and to set the monitoring parameters.

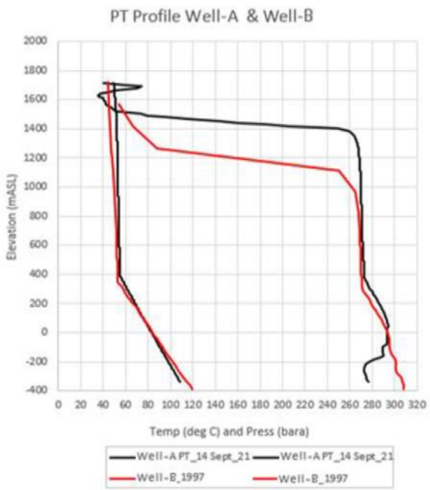


Fig. 3. Static pressure-temperature survey of Well-A (black line).

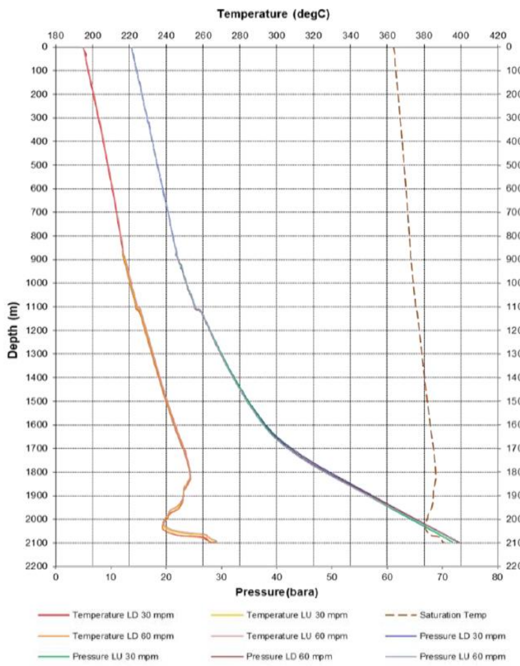


Fig. 4. Flowing pressure-temperature survey of Well-A (Jan 2022).

C. Casing Tally

The schematic of Well-A, shown in Fig. 5, indicates that this well contains a tie-back casing. Generally, tie-back casings are used to fix well integrity problems such as bad-cementing or corrosivity issues. Our capillary tubing was set at 1900 mMD in an 8.625-inch Production liner-2. Diameter information is used for the sinker bar calculations. Tally information is used for the run-in hole and pull out of hole (RIH-POOH) speed plan and safety of the operation.

D. Non-Condensable Gas Analysis Data

We collected two samples of gas analysis reports from the customer in 2021. In the gas analysis report of Well-A that is shown in Fig. 6, non-condensable gas (NCG) consisted mainly of carbon dioxide, which is typical in most geothermal wells. Also, the presence of hydrogen sulfide was relatively low. However, because gaseous corrosivity should generally be taken into consideration in geothermal applications, we chose nickel-chrome-molybdenum metallurgy for the capillary tubing.

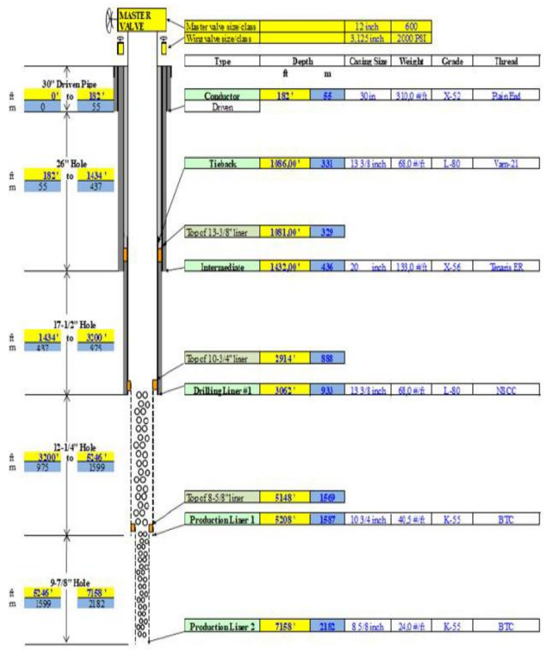
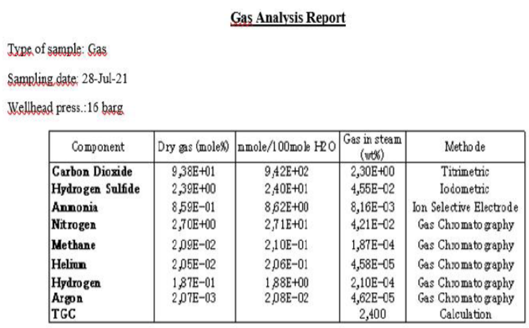


Fig. 5. Well schematic and casing tally of Well-A.



Gas Analysis Report

Type of sample: Gas

Sampling date: 28-Jul-21

Wellhead press.:16 barg

Component	Dry gas (mole%)	mmole/100mole H2O	Gas in steam (wt%)	Methode
Carbon Dioxide	9,38E+01	9,42E+02	2,30E+00	Titrimetric
Hydrogen Sulfide	2,39E+00	2,40E+01	4,55E-02	Iodometric
Ammonia	8,59E-01	8,62E+00	8,16E-03	Ion Selective Electrode
Nitrogen	2,70E+00	2,71E+01	4,21E-02	Gas Chromatography
Methane	2,09E-02	2,10E-01	1,87E-04	Gas Chromatography
Helium	2,05E-02	2,06E-01	4,58E-05	Gas Chromatography
Hydrogen	1,87E-01	1,88E+00	2,10E-04	Gas Chromatography
Argon	2,07E-03	2,08E-02	4,62E-05	Gas Chromatography
TGC			2,400	Calculation

Fig. 6. A gas analysis report of Well-A for preparation of DSI project (Jul-2021).

Water Analysis Report

Type of sample: Seperated water

Sampling date: 28-Jul-21

Wellhead press.: 16 barg

Component	Value	Unit	Methode
pH	4, 807		pH (Electrometric)
SiO_2	-	mg/kg	Spectrophotometric
B	392, 983	mg/kg	Titrimetric with Mannitol
Fe	-	mg/kg	Spectrophotometric
Li	0, 068	mg/kg	Ion Chromatography
Na	7619, 326	mg/kg	Ion Chromatography
K	1495, 240	mg/kg	Ion Chromatography
Ca	117, 337	mg/kg	Ion Chromatography
Mg	79, 928	mg/kg	Ion Chromatography
F	0, 037	mg/kg	Ion Chromatography
Cl	9798, 009	mg/kg	Ion Chromatography
SO_4	7388, 552	mg/kg	Ion Chromatography
HCO_3	8, 494	mg/kg	Titrimetric
TDS	26506, 99	mg/kg	TDS (Electrometric)

Fig. 7. A water analysis report of Well-A for preparation of DSI project (Jul-2021).

E. *Brine Water Analysis Data*

Fig. 7 shows a water analysis report of Well-A before the implementation of the DSI project.

Based on a simple equilibrium model, the wellhead brine was at saturation with respect to amorphous silica, indicating that amorphous silica deposition was not expected under these operating conditions in the Well-A well-bore or wellhead, but silica deposition could occur at relatively lower temperatures within the downstream of the power plant system (e.g., after flashing to lower pressure/temperature or possibly at the re-injection well). The low fluid pH would cause delay silica precipitation kinetics. Thus, indications of silica deposition in the well bore and wellhead may be expected rarely, only in transient conditions such as well start-ups or shutdowns.

We used a program to model the downhole conditions, where steam and brine was mixed to equilibrium conditions with gasses included at 192 °C. The equilibrium model indicated that calcium was under saturated with respect to calcite. This is commonly observed when calcite precipitation has occurred downhole, depleting the solution in calcium and carbonate alkalinity.

The brine was extremely high in sulfate, and this resulted in the fluid being supersaturated with respect to Calcium sulphate anhydrous. However, the kinetics of anhydrous precipitation were slow; therefore, we did not expect to see anhydrous scale in the well bore or power plant. Amorphous silica was slightly under-saturated at wellhead temperature, but this quickly reached saturation as the brine cooled through the brine piping system, resulting in silica deposition. As expected, calcite was under-saturated, because of the shallow, high enthalpy steam entries. This shallow steam mixes with the deep brine (reservoir pH level was probably about (6–7) and the acidic Carbon dioxide depresses the wellhead brine pH to 4.8. Most likely the deep liquid entries were supersaturated with respect to calcite, resulting in deposition of calcite at the downhole section.

Commonly, a caliper survey can identify the depth and severity of calcite deposition occurring in the well bore. Application of a calcite scale dispersant below the depth of calcite deposition was necessary to mitigate this condition.

In the first technical proposal we submitted to the customer, we warned them about the need for the application of an appropriate corrosion inhibitor that could be considered due to the low pH level (4.8) and the high chloride content. We installed deposit and corrosion coupons at the wellhead during the 3-month trial period. These coupons were analyzed to determine the types and mechanisms of scale deposition and/or corrosion occurring in this area. We promised to report and discuss results with the customer and recommend future actions if required.

After evaluating this information, we chose to use a scale dispersant as the pilot scale inhibitor into the well-bore liquid zone and Inconel 625 for the capillary tubing material. The selected scale dispersant is a proven calcium carbonate scale inhibitor used in hot temperature geothermal wells. Inconel 625 capillary tubing is a high nickel-molybdenum-cobalt alloy material that is durable to aqueous corrosive environments containing high chloride levels and low pH or acidic conditions.

III. Implementation of The DSI System

Downhole scale inhibition is the process of preventing the formation of scale from blocking or hindering fluid flow through pipelines, valves, and pumps used in oil and geothermal production and processing. Scale inhibitors (SIs) are a class of specialty chemicals that are used to slow or prevent scaling in liquid phase of systems.

a. *Installation*

The DSI dosing system, shown in Fig. 8, includes:

1. a dosing pump skid, which delivers scale inhibitor to a capillary tubing. a proper chemical storage tank.
2. a proper type of capillary tubing.
3. a pack-off mounted lubricator on the wellhead.
4. a BOP.

The bottom hole assembly, including inhibitor dosing nozzle and weight bars, deployed to the appropriate depth in the well.

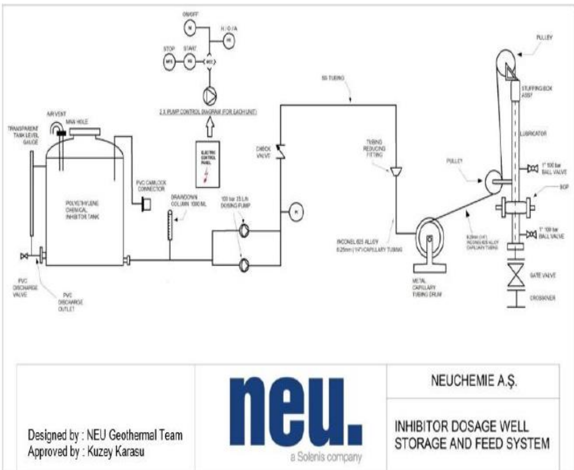


Fig. 8. Inhibitor dosage well storage and feed system for DSI system on Well-A.

The pump skid required to inject the scale dispersant to Well-A was designed specifically for the customer. The skid included two chemical diaphragm metering pumps (max pressure: 100 bars, capacity: 35 liter/h), one 5.000-liter cross-linked polyethylene chemical storage tank, chemical filters, a draw-down tube to measure dosage rate, associated tubing, valves, a dampener (to keep pressure of chemical injection consistently), and complete instruments.

For the chemical storage tank, we used a 5.000-liter capacity, cross-linked polyethylene inhibitor tank, with a 10-mm wall thickness, red colored tank. The tank is equipped with a manual fluid level gauge for easy and continuous monitoring. Inhibitor tank chemical output was made from the side of the tank to the dosing system with appropriate fittings and chemical resistant hoses close to the lower limit. A manhole cover with a 42-cm diameter provided access to the inhibitor tank.

For the capillary tubing, we needed 2200 meters, and we selected Inconel 625 (UNS N06625, B163) seamless tubing with a 0.25inch OD and a 0.035-inch wall thickness. Inconel 625 was selected for this application because it is a corrosion and oxidation resistant nickel alloy with high strength and outstanding aqueous corrosion resistance. Inconel 625 has excellent fatigue strength and stress-corrosion cracking resistance to chloride ions compared to the less expensive alternatives 316L stainless steel or 2205 duplex stainless steel tubing.

To hold the bottom hole assembly (BHA) and capillary tubing in place before the run-in hole (RIH) and after the pull out of hole (POOH) operations, a 16-foot carbon steel lubricator, as shown in Fig. 9, was used at the wellhead of Well-A. The lubricator included a hydraulic stuffing box (sealing box) at the top. To ensure smooth movement of the capillary tubing, two aluminum pulleys (sheaves) were mounted on the lubricator, one at the top and one near the bottom. The upper pulley could be moved in all directions. There was more than one 1-inch OD or ID, 316 stainless-steel, ball type relief valve on the lubricator. A thread-operated BOP was placed under the lubricator to be used in emergency conditions. The BOP had Viton® parts to prevent damage to the capillary tubing when closed. Flange types between the BOP and the wellhead crown valve were synchronized with a crossover sub.

Fig. 9. Lubricator with hydraulic stuffing box and crown pulley on the wellhead of Well-A.

TABLE I. SCALE DISPERSANT DILUTION AND DOSAGE TABLE OF WELL-A

ppm	Flow (kg/s)	Neat (g/min)	Chem density (g/cm^3)	Concentration (%)	Sol. Density (g/cm^3)	Neat (ml/min)	Sol. (ml/min)	Time for 200 cc (s)
50	65	195	1,2	16,67	1,03	188,7	1132	10,6
40	65	196	1,2	16,67	1,03	151	905,6	13,3
35	65	136,5	1,2	16,67	1,03	132,1	792,4	15,1
30	65	117	1,2	16,67	1,03	113,2	679,2	17,7
25	65	97,5	1,2	16,67	1,03	94,4	566	21,2
20	65	78	1,2	16,67	1,03	75,5	452,8	26,5
15	65	58,5	1,2	16,67	1,03	56,6	339,6	35,3
10	65	39	1,2	16,67	1,03	37,7	226,4	53
5	65	19,5	1,2	16,67	1,03	18,9	113,2	106

From top to bottom, the 13-foot bottom hole assembly (BHA) consists of a 6-inch stainless-steel capillary tubing holder, a 7-foot tungsten hollow bar, a 5-foot stainless-steel solid bar and a 6-inch stainless-steel bull-nose.

The scale dispersant selected for the control of calcite and other calcium scales in Well-A is a proven polymer blend that effectively inhibits precipitation of calcium carbonate, calcium oxalate, calcium sulfate and other low solubility salts. It has excellent chelation, low threshold inhibition and lattice distortion ability. In geothermal brine, it reduces scale formation, particularly for calcium carbonate. We conducted a thermal stability test of the scale dispersant to assure its performance in hot temperature and pressure well conditions.

The scale dispersant was diluted in 1:4 scale dispersant/dilution water and applied to the well-bore at a depth of 1900 mMD. The dosage rate was measured continuously by using a gradual cylinder, calculating the time of 200 cc consuming on a gradual cylinder. Table I shows detailed information regarding the application of the scale dispersant.

b. Monitoring

Proper monitoring program is essential to ensure that the DSI trial program were successfully. Along the trial process we collect data from brine water analyses and scale coupon analysis.

Fig. 10. Sampling point location (left), on-site sampling process (center) and on-site lab support (right).

1) Brine analysis monitoring

Water samplings were collected from the water phase from the flow line. To achieve accurate results, the best point on the pipeline was selected, as shown in Fig. 10. A sampling mini separator was installed, and the pressure and temperature of the separator was adjusted according to the flow. This way, flow-line simulation could be achieved within the separator. We prepared two sets of samples for separate analysis by our laboratory scientists and by our customer, and then shared our results.

The exact required dosage was established during the field test. This was determined and optimized within a few days of start-up. The optimization process was started with the trial using a maximum of 50 ppm, and all dosages of 10, 20, 30 and 40 ppm were tried every 2 days. At the end of the optimization process, an 8-ppm dosage was determined to be the optimum rate. The detail analysis result will be seen on the Fig. 12.

2) Scale coupon monitoring

In Well-A, we conducted a scale coupon analysis, to examine the results of scaling as another effective way. We saw the scaling and corrosion effects of the Well-A, visually and numerically with the scale coupon analysis. Since the beginning of the project, we had been taking photos of the scale coupon to collect evidence of scaling on the coupon.

Benefits of the visual observation of the coupon included observing any traces of:

1. scaling, which allowed us to maintain a double-check for chemical injection optimization.
2. plugging holes, which allowed us to see if anything else was produced from the well-bore.
3. corrosion, which allowed us to understand the type of corrosion.

The scale coupon, as shown in Fig. 11, that was used in Well-A for the DSI Trial project had a carbon steel tip.

We determined the sampling frequency of the scale coupon as more frequently of the DSI chemical treatment project. That time interval was the optimization period of the chemical dosage. Then, we decreased the frequency of analysis.

Fig. 11. Scale/corrosion coupon used in Well-A for the DSI project.

IV. Brine Analysis Results for Well-A

Throughout the project, we recorded the results of chemical sampling analysis and created a trend-line of the calcium removal performance, shown in Fig. 12, of the scale dispersant n Well-A. Within the 84-day period between 21 Jan to 15 April 2022, we managed to remove 40.24 tons of calcium from the system. Currently, we have no proper way to measure the calcite deposition rate in the system because no standardized method exists to predict or measure the scale deposition on the metal surfaces of geothermal wells. However, what we could do and predict was the mineral removal amount from the system based on hardness level analysis. In our case, the scaling mineral is a calcium-based scale.

Throughout the project, calcium hardness levels were in a decreasing trend-line, although the scale dispersant dosage rate was stable at 8 ppm. To determine whether the decreasing trend-line was independent of the chemical treatment, we also looked at the conductivity level trend-line of the geothermal fluid. The trend-line angle of the conductivity was the same as the trend-line angle of the calcium hardness, as shown in Fig. 13. These results prove that the scale dispersant still was able to prevent calcium scaling at its optimum rate.

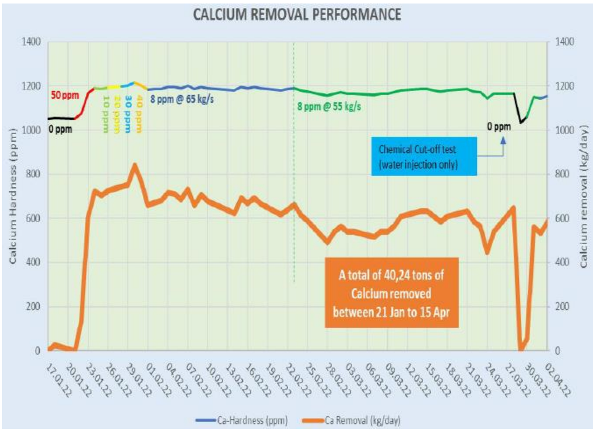


Fig. 12. Calcium removal performance of scale dispersant in Well-A.

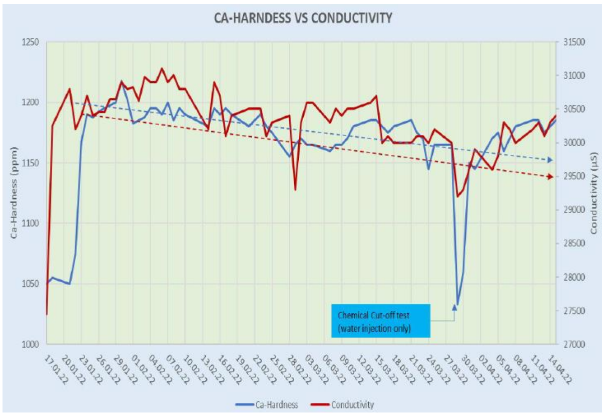


Fig. 13. Calcium hardness versus conductivity values, proving the decreasing trend is natural.

V. Conclusion

In January 2022, Solenis embarked on a joint project with a customer to fix the scaling problems in Well-A in the customer's geothermal field in Indonesia. As agreed by both parties, the project was named the downhole scale inhibition program (DSI) and preparations were started. Input data, including gas chemical analysis, water chemical analysis, historical information, feed zone data, well schematic, well static, and flowing pressure-temperature-spinner (PTS) surveys were collected. Using the data collected from the customer, Solenis completed the calculations and material selections and then supplied the necessary subsurface and surface equipment for the DSI project in Well-A.

During the DSI project, we successfully mitigated calcium scale in Well-A by removing from the system a total of 40.24 tons of potential calcium carbonate in the downhole system.

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