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CONTROL OF CALCIUM CARBONATE SCALE USING CONCENTRIC TUBING AT COSO GEOTHERMAL FIELD

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ABSTRACT

This paper reviews the history of efforts to control calcium carbonate scaling in the Coso Geothermal Field. It describes the use of concentric tubing (a capillary tube inside coiled tubing) to inject scale inhibitor downhole. The concentric tubing has been much more reliable as an inhibitor injection string than unprotected capillary tubing for Coso well conditions. The stainless steel capillary tube inside resists corrosion by the inhibitor, and the carbon steel coiled tubing provides the mechanical strength to withstand wellbore turbulence.

INTRODUCTION

The formation of calcium carbonate (CaCO3) scale in production wells has been one of the principal challenges in the operation of the Coso Geothermal Field. Coso shares this tendency toward CaCO3 scaling with numerous other liquid-dominated geothermal fields (Armansson, 1989; Benoit, 1989; Vaca et al., 1989). The scaling occurs when the boiling of reservoir fluid and the evolution of CO2 cause a rise in pH and an increased concentration of calcium and carbonate ions in the liquid phase, resulting in the supersaturation and precipitation of CaCO3 (Michels, 1981; Anorsson, 1989).

Several techniques to control CaCO3 scale have been tried at Coso, including mechanical clean-outs, acid stimulations, and downhole inhibitor injection. Of these techniques, inhibitor injection has proved to be the most cost-effective. Vaska and Kellogg (1989) have described the general technique of downhole scale inhibition. Field tests using this technique have been described by several authors, including Corsi et al.(1985), Pieri et al. (1989), Robson and Stevens (1989), and Rose (1989). All of these tests have used capillary tubing to convey the inhibitor downhole. At Coso, mechanical problems with capillary tubing installations have led to the use of concentric coiled tubing instead. The purpose of this paper is to trace the history of scale control efforts at Coso, to describe the current concentric tubing installations, and to discuss potential for further design improvements.

DESCRIPTION OF COSO RESOURCE

The Coso Geothermal Field, located approximately 200 miles north of Los Angeles in Inyo County, California (Fig. 1), produces from fractured crystalline rocks at depths ranging from 1,329 to 10,440 feet. Reservoir temperatures are between 400 and 650 degrees Farenheit, and static reservoir pressures are between 575 and 650 psig at a reference elevation of 2,000 feet above sea level. Withdrawals from the reservoir began in 1982 with the flow testing of individual wells. A 25-MW, dual-flash power plant initiated commercial production in July, 1987. A total of nine turbines are now operating at four plant sites, with a combined capacity of 240 MW.

The field is liquid-dominated, with a pre-existing steam cap which has been locally expanded through exploitation. The production wells are artesian and generally produce a two-phase mixture at the surface. The enthalpy of the produced fluid ranges from 400 to 1,150 BTU/lbm,

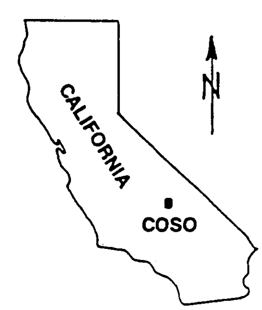

Figure 1. Location Map of the Coso Geothermal Field.

Table 1.
Coso Fluid Chemistry

	Pre-Flash Concentration (mg/kg)
Calcium	20 - 50
Magnesium	< 0.2
Bicarbonate Alkalinity	30 - 140
Silica	350 - 600
Total Dissolved Solids	3,700 - 8,000
Non-Condensible Gases	1,000 - 25,000
pH of Post-Flash Water	5.4 - 7.5

with the higher-enthalpy wells deriving some of their production from the steam cap. Flow rates from individual wells range up to 1,100 KPH (thousand pounds per hour) and are typically between 200 and 800 KPH. Flowing wellhead pressures range from 100 to 200 psig in wells that are prone to scaling. Table 1 summarizes aspects of the produced fluid chemistry that pertain to a tendency toward scale formation.

WELLBORE COMPLETIONS

The wells at Coso are generally completed with 13-3/8" casing cemented above the productive interval at depths ranging from 1,500 to 2500 feet. A 12-1/4" hole is drilled through the productive interval and is lined to total depth with a 9-5/8" slotted liner. The liner has been found to be necessary to prevent wellbore collapse and to minimize the production of rock fragments. Most of the wells are directionally drilled below the 13-3/8" casing, with deviations from vertical ranging up to 30 degrees. Figure 2 shows a schematic of a typical wellbore completion.

OCCURRENCE OF SCALE

Calcium carbonate ($CaCO_3$) scale has been observed in 28 out of 61 productive wells at Coso. The $CaCO_3$ scale is always sub-surface, at measured depths ranging from 1,300 to 3,500 feet. X-ray diffraction of scale samples has shown them to be approximately 50% calcite and 50% aragonite. The bottom of the scaled interval appears to correspond to the flash point under flowing conditions. Usually, this places the majority of the scale within the 9-5/8" liner, but the top of the scale often laps over into the 13-3/8" casing. Individual wells have been observed to have scaled intervals in excess of 2,000 feet. In the absence of scale inhibitor treatment, some wells have scaled up completely in less than two weeks.

Three empirical criteria have been useful in predicting which wells at Coso are susceptible to scale. The first criterion is a produced fluid enthalpy corresponding to a saturated liquid temperature less than or equal to the maximum downhole temperature. Wells which meet this criterion produce most of their mass from single-phase liquid entries and flash primarily in the wellbore. Wells with higher enthalpies have two-phase entries due to flashing in the reservoir, and they tend to have little or no wellbore scale. This is consistent with the observations of Arnorsson (1989), who has suggested that flashing and deposition of $CaCO_3$ scale at some distance back in the formation has comparatively little adverse effect on productivity.

The second criterion is a calcium concentration below about 20 mg/kg in the post-flash produced water. Since 20 mg/kg is the bottom of the range of pre-flash calcium concentrations at Coso, lower values in the post-flash water (which should be more concentrated) indicate that calcium is being left downhole as $CaCO_3$ scale.

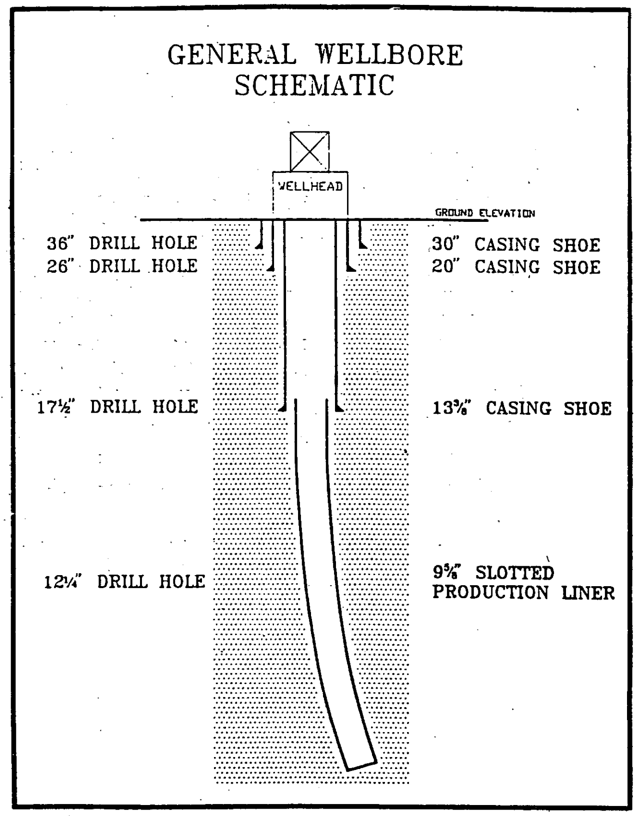

Figure 2. Typical Wellbore Completion, Coso Geothermal Field.

The third criterion is a total mass flow rate of 600 KPH or greater. This criterion can help distinguish among wells which meet either or both of the other two criteria. Wells with higher flow rates tend to scale more quickly simply because their mass throughput is greater.

TREATMENT OF SCALE

The occurrence of $CaCO_3$ scale at Coso became apparent within a few months of starting up the first plant. Three of the ten wells supplying the first plant were affected, including two of the most prolific producers. The initial response was to clean out the affected wells with a drilling rig, but the frequency and expense of these clean-outs made them unacceptable as a primary method of scale control. Scale growth was too rapid to allow varying wellhead pressure to distribute the scale in the wellbore and decrease workover frequency, as has been suggested for Dixie Valley (Benoit, 1989). Acid stimulations to clean out scale in the wellbore were also impractical because of the length of the interval to be treated and the difficulty of protecting the 9-5/8" liner from acid attack at reservoir temperatures. Attempts were made to keep the affected wells clean by frequent runs of cutting tools and jars on wireline, but these tools were not effective and frequently got stuck.

In the summer of 1988, a program of downhole inhibitor injection was implemented for the two largest wells affected by scale. Both these wells had been cleaned out three times in the previous year. A 1/4" capillary tube made of 316 stainless steel was run into the wells through the crown valve on top of the wellhead. Inhibitor was pumped continuously through the tubing to a depth below the flash point in the wells.

The treatment dramatically improved the performance of both wells. One of the wells has not needed a clean-out in almost two years since inhibition started. Gage ring runs in this well have shown that scaling has been virtually eliminated. In the second well, $CaCO_3$ scaling has continued but at a much reduced rate. It is not clear whether the residual scaling in the second well is due to imperfect inhibitor performance or a mechanical limitation in inhibitor placement. However, the time between clean-outs for this well has increased from roughly 2 to 9 months.

INHIBITORS USED

At the start of the inhibitor injection program at Coso, two types of inhibitor were tested: polymaleic anhydride (PMA) and a polyacrylate/terpolymer blend. The PMA proved to be the more effective of the two and is currently the only inhibitor in use at Coso. The polyacrylate/terpolymer blend appeared to have problems with plugging the capillary tubing at formation temperatures. The use of phosphonate inhibitors was not tried because of concern that these could break down to orthophosphate at formation temperatures and lead to the formation of insoluble calcium orthophosphate scale.

The current inhibitor program at Coso involves injecting a PMA product at 8 to 10 gallons per day per well. This yields an effective concentration in the liquid phase of 2.5 to 5 ppm. It is possible that the PMA would be equally effective at lower concentrations. However, many of the wells tend to surge over periods that range from several seconds to tens of minutes. The surging represents variation in the steam fraction of fluids flowing up the wellbore and makes it difficult to accurately determine the two-phase flow rate at any instant. For this reason, no great emphasis has been placed on fine-tuning the inhibitor dosage to a bare minimum. Based on bulk pricing, the current program costs about $30 to $45 per day per treated well, depending on the flow rate.

CONCENTRIC TUBING INSTALLATIONS

Although the first two installations of 1/4" inhibitor injection tubes were quite successful and lasted over six months, subsequent 1/4" installations in new wells in the spring of 1989 suffered repeated mechanical failures. The failures seemed to be related to the high flow rates of the wells and possibly to wellbore restrictions from pre-existing scale formed during initial flow testing. It was unclear whether the 1/4" tubes failed by being blown up from the bottom of the hole or by parting near the surface due to abrasion in the wellhead. The condition of the tubing after it had been extricated from wellheads, flowlines, and separators did not provide much insight into the mode of failure. The amount of weight that could be suspended from the bottom of the tubing to keep it in the hole was limited by the length of lubricators on the wellhead. Several installations were performed with a larger size of capillary tubing (3/8"), but the majority of these also failed.

The concentric tubing design has grown out of an attempt to solve these problems with capillary tubes. The design consists of a capillary tube (through which the inhibitor is pumped) inside a sheath of coiled tubing. The capillary tube, made of 316 stainless steel, provides resistance to the corrosive effects of the inhibitor. The coiled tubing, made of carbon steel, provides the mechanical integrity to withstand the turbulent flow in the wellbore and also protects the capillary tubing from chloride stress corrosion which could be caused by exposure to chlorides in the produced fluid.

The first concentric tubing used at Coso consisted of 1/8" capillary tubing inside 3/4" coiled tubing. This string was installed by running the coiled tubing into the well, then inserting the 1/8" with a pack-off and "pumping" the 1/8" through the 3/4" by pressuring up on the annulus between the two. The operation was successful but not repeated.

The next generation of concentric tubing used 1/4" capillary tubing inside 1" coiled tubing. The 1/4" was inserted in these strings in a similar fashion (i.e., by being "pumped" through), but the operation was performed by a service company off-site, with the 1" rolled out flat on the ground. These strings were successful in their function of transmitting scale inhibitor down production wells with a minimum of mechanical problems. Their chief drawback was the cumbersome manufacturing process.

The current generation of concentric tubing is specially manufactured at a tubing mill with 1/4" capillary tubing inside 1-1/4" coiled tubing. The 1/4" capillary tubing is still 316 stainless steel with a 0.035" wall thickness. The 1-1/4" coiled tubing has a 0.095" wall thickness. Odd lengths of this concentric tubing may be spliced together by using a tube fitting union on the capillary tubing, pulling up slack on the coiled tubing, and welding the two coiled tubing ends together.

OTHER EQUIPMENT

Several other equipment modifications have been implemented at Coso in connection with downhole inhibitor injection. An extra port anging 45 degrees from vertical has been added to the expansion spool on the wellhead. This allows the inhibitor string to be run into the well without blocking the use of the master valves. Figure 3 shows an old installation with 3/8" capillary tubing fed through a lubricator on the 45-degree port. Figure 4 shows a more recent installation with concentric tubing projecting from a stuffing box on the 45-degree port. A tee at the end of the 1" coiled tubing allows access to the annulus between the coiled tubing and the capillary tubing.

The assembly on the bottom of the inhibitor injection string has also

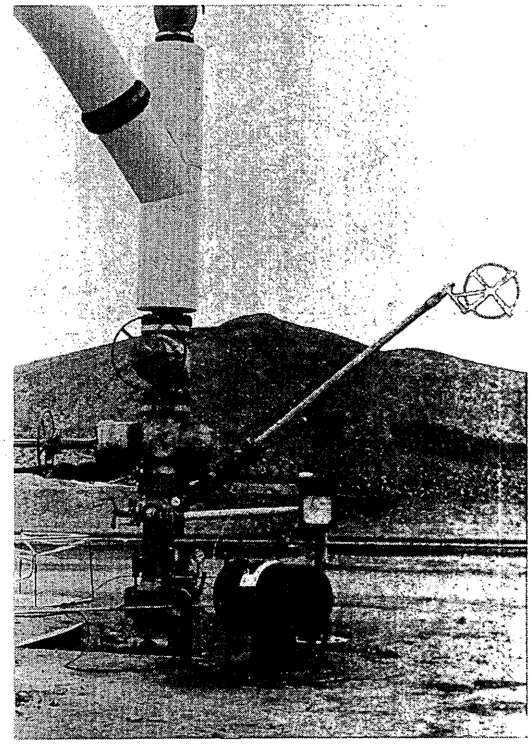

Figure 3. Wellhead with 3/8" Tubing Entering Lubricator on 45-Degree Port, Coso Geothermal Field.

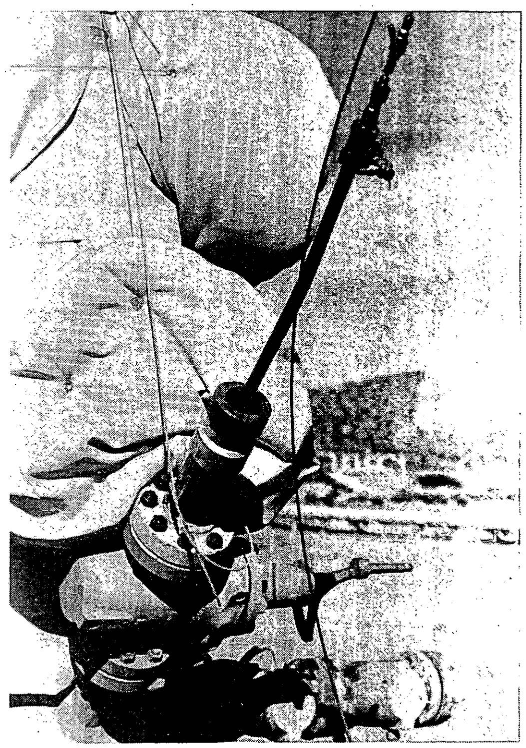

Figure 4. Wellhead with Concentric Tubing Entering Stuffing Box on 45-Degree Port, Coso Geothermal Field.

evolved. The rigid sinker bars in use when the injection string was run through the top of the wellhead were replaced with "sausage bars" (Fig. 5, foreground) which could feed through the 45-degree port. These are short, stainless steel weights threaded together with aircraft cable. When concentric tubing replaced the simple capillary tubing, the sausage bars lost their original function as weights. However, they have proved very useful as guides to help direct the coiled tubing through the top of the 9-5/8" liner, especially in deviated holes.

Figure 6 shows two versions of the inhibitor dispersion chamber and the chamber head. The "doorknob" on the bottom of the left-hand dispersion chamber was intended to guide the coiled tubing through the 9-5/8" liner top without the use of the sausage bars. It proved to be unsuccessful because its diameter was restricted to what would fit through the 45-degree port at the wellhead. The right-hand version illustrates how the dispersion chamber was assembled on the bottom of the 1/4" capillary tube. With a concentric tubing string, the coiled tubing is threaded into the top of the chamber head.

Figure 7 illustrates the importance of maintaining a continual supply of inhibitor to any producing well that is prone to scale. In this case, $CaCO_3$ scale formed on the outside of a 1/4" inhibitor injection string. The onion-like layering suggests that the thick, white portions of the scale formed during relatively brief periods when the flow of inhibitor was interrupted, while the thin, dark bands represent long periods when the inhibitor was active and the rate of scaling was slow. Figure 8 shows a typical inhibitor pump and storage tank. The pump has a gauge to monitor the inhibitor injection pressure, which typically runs around 200 psig. The tank and lines are insulated and heat-traced to prevent freezing.

CONSIDERATIONS FOR TUBING INSTALLATION

Field experience at Coso has shown that there are several important factors to be considered in installing an inhibitor injection string. First, the bottom of the tubing must be below the flash point to get the maximum benefit from the inhibitor. The flash point may be determined by the gradient of a flowing pressure survey, or it may be inferred from the bottom of existing scale based on a caliper survey or a recent clean-out. One should make allowances for the fact that, as reservoir pressures decline, the flash point will be moving down the well. On the other hand, one should avoid running the injection string too deep. If the dispersion chamber is below the bottom entry, the inhibitor may not be effectively carried up the well. Spinner surveys and mud logs to identify fluid entries are useful in this regard.

To avoid plugging the capillary tubing on a new installation, it is good practice to establish an injection rate through the capillary tubing with clean water before starting inhibitor injection. It may be necessary to dilute the inhibitor product to achieve a sustainable injection rate.

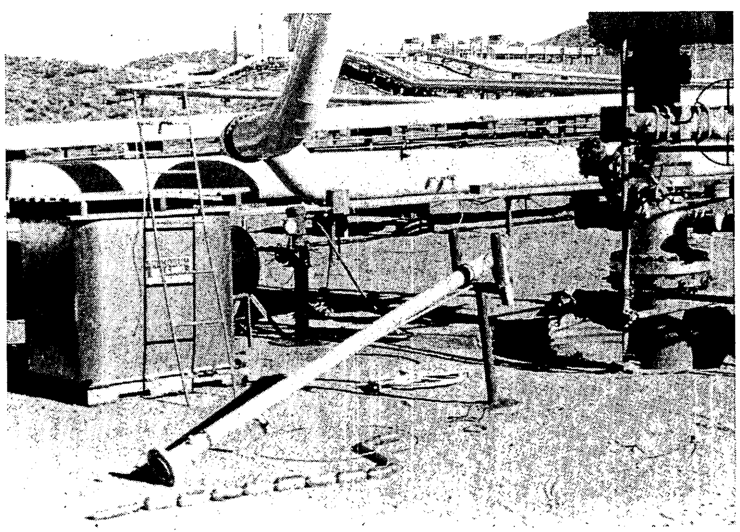

Figure 5. Wellhead with Lubricator Disconnected and Sausage Bars in Foreground, Coso Geothermal Field.

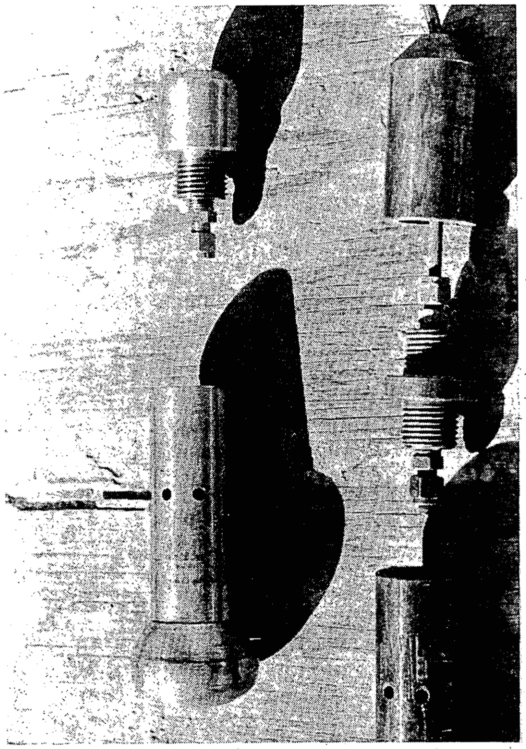

Figure 6. Dispersion Chambers and Chamber Heads. Left: for 1" Concentric Tubing. Right: for 1/4" Capillary Tubing. Coso Geothermal Field.

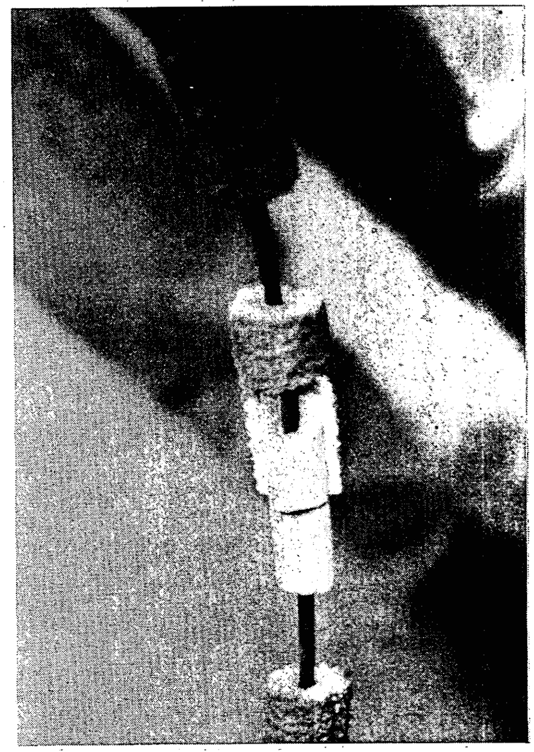

Figure 7. $CaCO_3$ Scale Formed on Outside of 1/4" Inhibitor Injection Tube, Coso Geothermal Field.

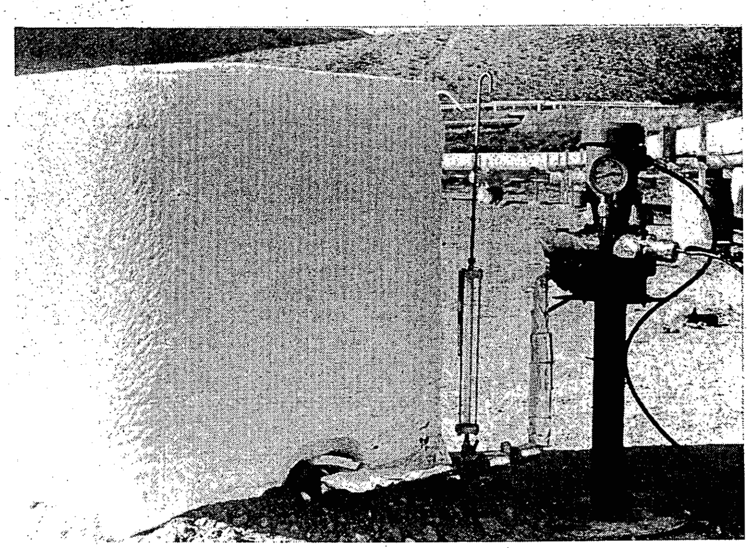

Figure 8. Inhibitor Injection Pump and Storage Tank, Coso Geothermal Field.

Also, the annulus between the capillary tubing and the coiled tubing should be kept as free as possible of formation fluid to avoid chloride contact with the stainless steel capillary tube. A pressure test of the annulus before running the tubing in the hole is useful to check for leaks and may be performed periodically to monitor the integrity of the system. Finally, one should plan on pulling the inhibitor injection string out of the hole periodically to check for incipient problems. The timing of such inspections will be determined by field conditions.

FUTURE DEVELOPMENT

The presence of an annulus in the inhibitor injection string leaves open the possibility of installing additional reservoir monitoring devices, such as another capillary tube for measuring downhole pressure or a thermocouple for measuring downhole temperature. Knowing these parameters would be particularly useful as a well's flash point migrates downward, because one could then determine if the dispersion chamber was still within the liquid phase. Such installations are being considered for selected wells in the Coso Field.

CONCLUSIONS

1. Downhole inhibitor injection has been the most cost effective means of controlling $CaCO_3$ scale in the Coso Geothermal Field.

2. Concentric coiled tubing has proved to be more reliable than unprotected capillary tubing as an inhibitor injection string for Coso well conditions.

3. The success of downhole inhibition depends on insuring that the inhibitor dispersion chamber is properly placed and that the installation is in good mechanical condition.

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