Geothermal Resources Council Transactions, Vol. 24, September 24-27, 2000

Acidizing Geothermal Wells

Umran Serpen, Ö Inanç Türeyen

Petroleum and Natural Gas Eng. Dept. of Istanbul Technical University

ABSTRACT

Substantial calcite scaling has been throttling the geothermal wells in short time span and thus limiting the power generation in Kizildere geothermal field. The cleaning of wells by mechanical methods has been adopted as a solution, but, has not succeeded in recovering the original flow rates. Application of scale inhibition, on the other hand, was found to be uneconomical. Consequently, acidizing has been considered as the only remedial measure.

This study examines the results of acidizing operations carried out in Kizildere field. Acid types, concentrations, additives and operation procedures are discussed. The results of well and production tests, conducted before and after the acid jobs, are presented. Possible formation damage caused by scaling in the fractures is examined. The effect of acid on calcite and dolomite is investigated. New acid compositions, additives and operation procedures to increase the acidizing efficiency are proposed, and recommendations are reported.

Introduction

Calcite scaling was a well known problem ever since the Kizildere geothermal field had first been discovered, and the decision was taken at early stage to periodically ream (mechanical cleaning) the production wells during the exploitation stage of the field. As indicated in Table 1, the first reaming operation was carried out in 1984. The reaming of calcite scales on the existing 6 production wells back then, was considered to be a way of preparation for early exploitation. Such remedy, however, did not yield considerable increase in production. The reason for this could be that not enough calcite had precipitated in the previous production tests up until then.

After two years of production, reaming on the 6 wells resulted in a 100% increase in production, which turned out to be more than the total production in 1984 as shown in Table 1. In 1986, three new production wells were added to the field totaling the number of production wells to 9, however towards the end of 1987, the total production decreased to 264 tons/h. Hence, a reaming operation was carried out on all 9 wells of which 7 were acidized. The total production then increased 810% up to 2405 tons/hr. In the subsequent years, these wells were cleaned during exploitation of the field with the use of a RCHP (Rotating Control Head Preventer) since it was believed that the mud and calcite cuttings got into the fractures in reservoir during the reaming process and caused formation damage. However, as seen from Table 1 the RCHP method, which was carried out in 1992, gave no better results than that of the one carried out in 1986 with 6 wells.

It is clear from Table 1 that the reaming operation, conducted on all wells and 5 of which were acidized in 1992, brought no significant increase in total production. Note that the reservoir had experienced a very minor pressure decline due to a limited production by then, and actually some increase in productivity should be expected from the contribution of the evolved free

Table 1. Calcite Reaming Operations in the Past.

Years	Calcite Elimination Method	W* ton/hr	W** ton/hr	Percent Increase In Production	Explanations
1984	Drlg. w/mud	1200	1210		6 production wells
1986	Drlg. w/mud	706	1415	100	6 production wells
1987/1988	Drlg.w/water + acidizing	264	2405	810	9 production wells, 7 wells are acidized
1990	Drlg. w/water + acidizing	507	1437	185	A single well was reamed with RCHP
1991	Drlg. w/ RCHP	748	1475	97	All wells were reamed with RCHP
1992	Drlg. w/ RCHP + acidizing	649	1507	132	5 wells were reamed with acid
1993	RCHP	645	1317	104	8 wells were reamed.

* Production before reaming
** Production after reaming

CO_2-rich gas phase. Hence, after the reaming operations conducted in 1993, the total production was 200 tons/hr lower than the previous level as it can be observed in Table 1.

Formation Damage due to Scaling

When the field was first discovered the original reservoir pressure sustained the flashing point level of the CO_2 and steam within the well. Hence, precipitation took place only a few hundred meters above this point within the well. In an MTA (Mineral Surveying and Exploration Institute) report, Özkan, (1987) stated that the flashing points were in between 450 and 550m varying from one well to another. As a result, it is possible to say that in shallow wells (such as the 510 m deep KD-15 well) the flashing point might have already moved into the reservoir. Other studies (Alkan et.al., 1990, Satman et.al., 1996, Serpen et.al.1994) have indicated that two-phase flow in the reservoir started after 1988. It is clearly seen from the well logs (Serpen et. al., 1995) that precipitation in the reservoir had started. The precipitation causes formation damage, which reduces the flow from the reservoir to the well. That is observed as a decline in production and/or as a skin factor in well tests (Serpen, et.al., 1998). However, production alone may not be reliable enough because it could decline as a result of pressure drop in reservoir or a reduction in the wellbore diameter due to precipitation.

On the other hand, within the limits of this study, no consistent results could be obtained due to poorly designed well tests. The results of the MTA studies (Durak, et.al., 1993, and Özkan, 1987) pointed out that the skin factors before the acidizing operation varied between 20 and 50 and dropped to negative values varying between 0 and -4 after the acidizing operation. To obtain more reliable information on the skin factor the following relationship was used in this study. The skin factor shows an improvement around 3.5 and 4 using this technique after the reaming and acidizing operations for the KD-21 well whose PI values were known.

$$DR = \frac{\text{PI (after acidizing)}}{\text{PI (after reaming)}} = \frac{\ln(r_e / r_w) + s}{\ln(r_e / r_w)}$$

Where:

PI = Productivity index
DR = Damage Ratio,
r_e = Drainage radius,
r_w = Wellbore radius,
s = Skin factor

Table 2. Flow Rates and WHP's of Wells Reamed in 1988.

	Before Reaming			After Reaming		
Well No	WHP (bar.g)	W (kg/s)	P.I.*	WHP (bar.g)	W (kg/s)	P.I.*
KD.13	17.2	19	16.1	17.9	43	187
KD.14	9.7	1.73	0.08	15.8	39	118.2
KD.15	8	19.5	0.85	16.7	41.7	26.9
KD.16	12	11.1	0.69	15	36	240
KD.20	15.2	35	4	17.5	58.6	178
KD.21	15.3	23.3	1.46	18	58.6	44
KD.22	16.2	15	3.36	17.8	45.8	68.4

*: P.I. kg/hr/bar

Table 3. Flow Rates and WHP's of Wells before/after Reaming Operations.

Wells		KD 6*	KD 7*	KD 13	KD 14	KD 15*	KD 16	KD 20	KD 21*	KD 22
Before Reaming	Q, ton/hr	60	-	70	95	-	174	90	90	70
and acidizing	WHP, kg/cm²	15	15	15	15	15	15	15	12.7	15
After Reaming	Q, ton/hr	130	100	170	150	156	276	210	165	140
and acidizing	WHP, kg/cm²	15	15	15	15	15	15	15	12.7	15

* These wells have been acidized.

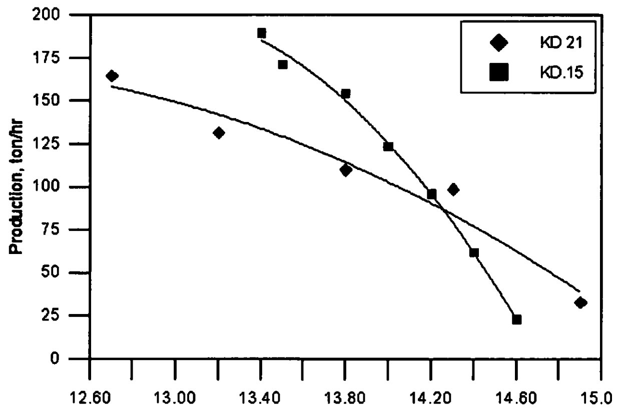

Figure 1. Production performances of the KD-15 and KD-21 wells after acidizing.

The results of the reaming and acidizing operations conducted in 1988 and 1992 are given in Tables 1, 2 and 3. Although similar acidizing techniques had been applied, the results for 1988 operation were better than those for the subsequent years. The main reason for the contradictory results is that in 1988, when the flashing point for many wells was already down at the reservoir, and the acid stimulation dissolved not only the scales but also the surrounding rock (marble) in the near wellbore region. As shown in Table 2 wells (KD-15, KD-21) were sustaining flow rates of 150-200 t/h at wellhead pressures of 17-18 bar in 1988. On the other hand, the results of reaming and acidizing in 1992 (Table 3 and Figure 1) indicated that the same wells could not produce at all at wellhead pressures beyond 15 bars, even though they were acidized wells. The flashing point already down at the reservoir caused precipitation within the fractures. It was understood that the acid was not effective in the deeper parts of the fractures. In 1992, the acidized wells KD-15 and KD-21 exhibited only a very minor production at the well head pressure of 15 bars. These results clearly point out that the late acidizing operations were not successful.

Acidizing the Scales in Kizildere Wells

Same acidizing techniques were applied to all wells by injecting a mixture of 40 m^3 of 28% HCl and 150 L of corrosion inhibitors at a rate of 70 m^3/hr. The injection was performed through drill pipe, while keeping the annulus blocked by the blow out preventer. The acid was displaced through the casing from the wellhead only in KD-21 well. The efficiency of acidizing operation was investigated in KD-13 well, in which a fracture is located at the depth of 730 m as the casing was set at the depth of 600 m. The presence of multi fractures in other wells complicates the study.

A temperature survey was taken after a cooling operation with unknown quantity of water in KD-13 (196°C) indicated a bottomhole temperature of 49.5°C. By using the Squire, et. al., (1962) model for this well the bottomhole temperature is estimated to be 84°C, after cooling, with 200m^3 of water (ordinarily applied for cooling before acidizing). The cooling within the fracture is computed starting with these two bottomhole temperatures. The estimated temperature along the fracture as a function of distance is shown in Figure 2.

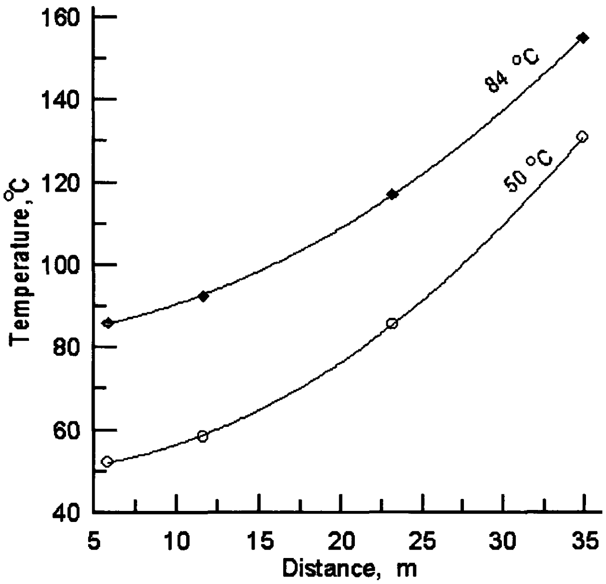

Figure 2. Temperature distribution after water injection at various bottomhole temperatures.

The radial penetration of acid is estimated to be 50 m by using the Terril (1965) model. However, it is also determined from the same model that the acid was not effective at this distance and the concentration declined to 3% at 14 m. Figure 3 illustrates the change of acid concentration along the fracture. HCl used in the acidizing operation reacts with the precipitated calcite ($CaCO_3$) along with marble formation of the Kizildere reservoir. It was always believed that the marbles were formed by the metamorphosis of limestone ($CaCO_3$). Well logging surveys conducted in 1988 indicated that the marbles might be of dolomitic origin. An

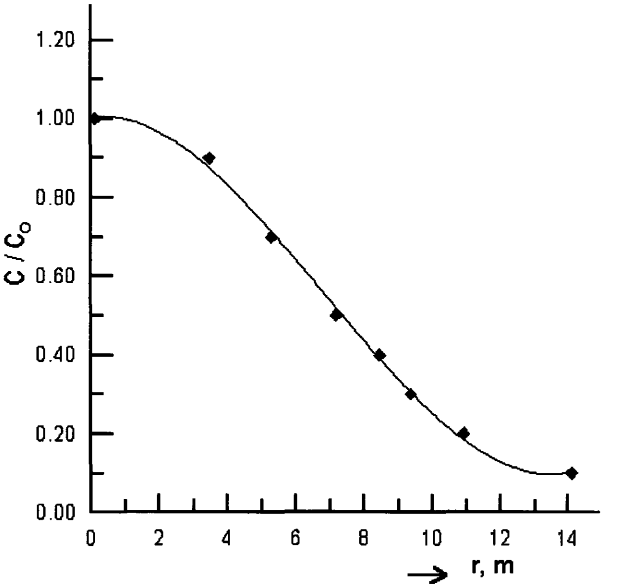

Figure 3. The variation of acid concentration along the fracture.

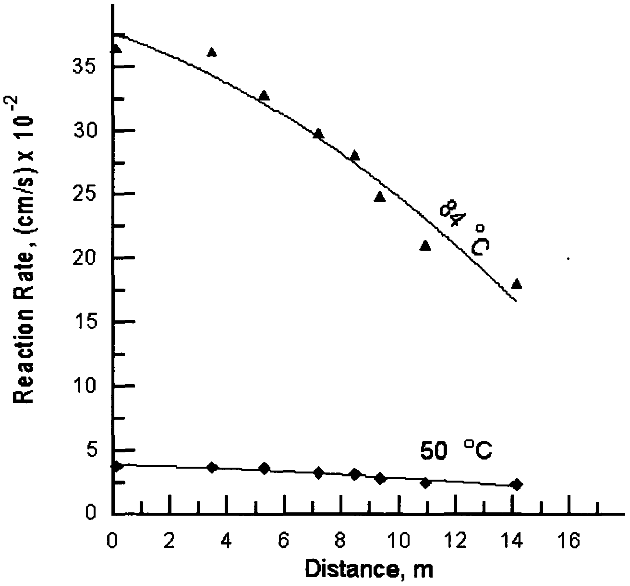

Figure 4. Reaction rates of dolomite along the fracture.

X-ray difractometer analysis confirmed that the marbles were consisted of 93% dolomite, [$CaMg(CO_3)_2$]. The reaction rates of HCl with dolomite and limestone are different.

Studies (Chatelain, et.al.,1976 and Nierode et. al., 1976) indicate that the reaction rate is controlled by reaction kinetics for dolomite and mass transfer for limestone. This mechanism, which is only one of the parameters controlling reaction rate, also effects the spread distance. Other factors affecting the distance are primarily temperature, concentration, fracture width and injection rate. As these parameters increase, the penetration distance of the acid increases as well and this distance for dolomite is always longer than that of for $CaCO_3$. An interesting point to note is that as the temperature increases, the reaction rate for dolomite transforms to mass transfer and approaches

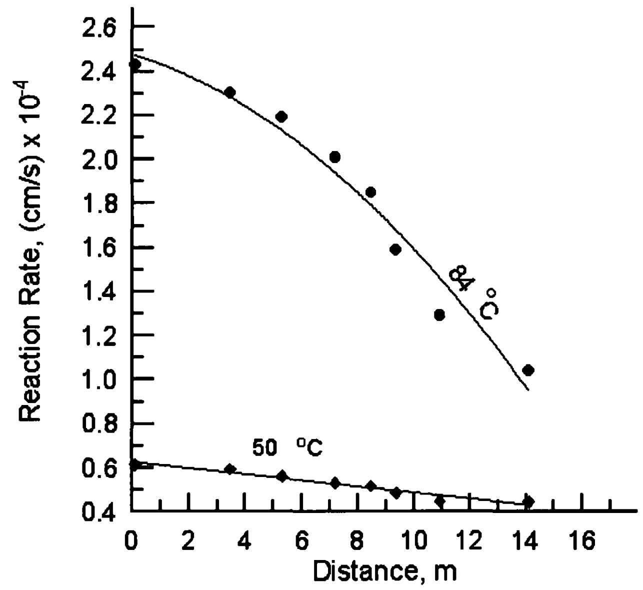

Figure 5. Reaction rates of calcite along the fracture.

Table 4. The Amount of Acid Spent within Wellbore during the Acidizing Operation.

		Amount of spent acid, ton	
Temperature, °C		**50 °C**	**84 °C**
CaCO3	1 cm	0.07	1.32
	2 cm	0.14	2.7
CaMg(CO3)2		0.1	0.3

the reaction rates for $CaCO_3$. This is rather important for geothermal wells. The reaction rates with dolomite and $CaCO_3$ for different temperatures along the fracture are shown in Figures 4 and 5. A significant difference is observed between the two minerals where the reaction rate for $CaCO_3$ is much greater.

During the operation, acid in the KD-13 well was in contact with the open hole as it was displaced from the casing shoe to the fracture. Taking this into account, the amount of acid consumed in the wellbore is computed, and the amount of acid spent in the fracture is estimated. The results are illustrated in Table 4. Two different bottomhole temperatures and a thickness of 1 and 2 cm of precipitated $CaCO_3$ are assumed in calculations. As can be seen from Table 4, especially at high temperatures, the amount of acid used for the precipitated $CaCO_3$ within the wellbore is quite high. Therefore, most of the acid is spent before it reached to the fracture.

Acid Retardation

The results of this study point out the importance of acid penetration into the fractures as deep as possible. This is possible only by means of acid retardation conducted with either one of the following applications :

- chemical retarders,
- gel acid or emulsion acid,
- organic acids,
- acidizing techniques.

There are many commercial chemical retarders available. However, these retarders may not be effective during flow, since the flowing acid exposes the preventer film to chemical erosion. CO_2 injection and adding $CaCl_2$ into the HCl acid are the other chemical methods. These latter chemicals may partially prevent the acid reactions and act as retarders. The industry's response to this prevention is to increase the acid concentration. These chemicals, which are also the by-products of the same reaction, have the same effect in higher concentrations. Such application has already been practiced in Kizildere geothermal field. Besides, Serpen et.al., (1995) proved that there are free CO_2 accumulation zones within the Kizildere reservoir, as illustrated in Figure 6. Should these intervals had been acidized selectively, the existing CO_2 in the reservoir would have served as the retarder.

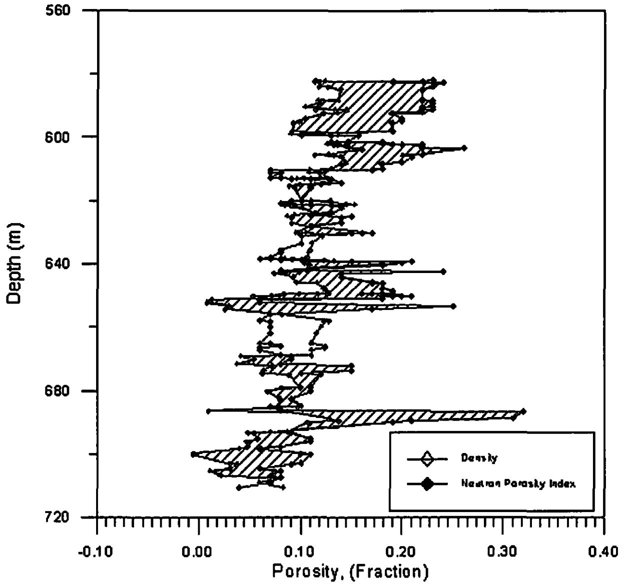

Figure 6. CO_2 bearing zones at the KD-13 well.

Emulsion or gel acid options are not considered suitable for high temperatures. Although the reservoir is cooled down, prolonging the reaction time would cause the polymers used in emulsion and gels to break down.

Organic acids, such as acetic acid and formic acid, are ordinarily mixed together with HCl to obtain an even more efficient retarder. This is because the reaction rates of the organic acids are lower than the HCl reaction rate. On the other hand, the CO_2 produced as a result of the reaction between the organic acid and carbonate rock acts as a buffer and suppresses the further acid reaction with increasing temperature. This is especially critical for acetic acid, of which half of the total amount does not react at 65°C. It is also obvious that CO_2, formed as the result of HCl and carbonate rock reaction, will prevent acetic acid from reacting. Calculations conducted indicate that a 15% HCl along with acetic acid will impede the reaction of 66.5% of the total acid.

One of the main parameters controlling the reaction rate of the acid is the leak off through the fracture surface. The lower the leak-off rates, the longer the distance traveled by the acid without being used up. The conditions in Kizildere field are appropriate for this mechanism to take place, because the permeability of marbles is insignificant. An alternate technique is the injection of a viscous fluid at the acid front, which would effectively cool the fracture and change the ratio of surface area-to-acid volume by opening out the fracture to let acid go deeper. Furthermore, increasing the acid viscosity would result in a decrease in the mass transfer rate on the fracture surface. It ought to be taken into account that the acid and dolomite mineral contact in the formation should be prevented. Consequently, the acid could be used only to dissolve calcite scale within the fracture. In this type of selective stimulation, the packer should be set just above the fracture, and the acid should be injected right into the fracture.

Discussion and Results

It should be clear by now that the $CaCO_3$ precipitation has the tendency to move from the wellbore into the fractures as the reservoir pressure declines. Additionally, higher flow rates cause the precipitation to go deeper in to the reservoir through the fractures. Therefore, reaction time of the acid has paramount importance. Yet, the reaction of the acid with the reservoir rock, particularly the marble, complicates the operation. It should be noted that the reaction rate of the acid with the $CaCO_3$ is much higher than that of with the dolomitic marbles, at lower temperatures. The use of a high HCl concentration (28%) yields a longer reaction time and causes the precipitation of a by-product mineral (tachidride) in dolomite. It is known that a 3800 L (1000 gal) of 28% HCl acid is capable of generating about 210 kg of tachidride ($CaMg_2Cl_6.12H_2O$) precipitate. Therefore, 40 m^3 of acid generates 2200 kg of tachidride to precipitate within the fractures. Although the injection of 90 m^3 of fresh water as after flush alleviates the tachidride problem, there might still be a considerable amount of tachidride precipitate left or transported elsewhere in the reservoir.

As shown in this study, the acid reaction rate is greatly affected by the temperature. Both the bottomhole and the fracture should be kept as cool as possible, so that the acid consumption could be delayed, allowing the acid to travel deep into the formation. The heat from the surrounding rock increases the temperature to its original value within a very short period of time. In this case certain acid mixtures or additives are to be used to turn this event into an advantage.

Organic acids may be considered as retarders. Since acetic acid seems to have some disadvantages associated with it, formic acids could be used along with HCl for this purpose. Furthermore, it should also be taken into account that small amounts of formic acid also acts as a corrosion inhibitor.

Standard techniques are adopted for acidizing operations in Kizildere geothermal field. If a particular well contains more than one fracture, then, it is obvious that the injected acid would be divided into smaller fractions within each individual fracture. Thus, the entire acid cannot penetrate deep in to the fracture and be confined to the near wellbore region. In such cases, inflatable packers should be used to isolate the individual fractures, and the acidizing be conducted selectively.

Conclusions and Recommendations

- The bottom hole cooling should be maintained for sufficient periods of time prior to acidizing.
- The acid design should be made so that the tachidride precipitation, caused by the use of high concentration HCl acid, is avoided.
- The use of organic acids and retarders should be considered, preferably after a detailed screening.
- The retarding effect of in-situ generated CO_2 should be made beneficial.
- Experimental studies conducted with various acid compositions in representative reservoir cores are recommended.
- Selective stimulation should be used to acidize individual fractures.

References

Alkan H., Satman A., 1990: New Lumped Parameter Model for Geothermal Reservoirs in the Presence of Carbon Dioxide, *Geothermics* Vol.19 No.5, 99469-478.

Chatelain J.C., Silberg I.H., Schechter R.S., 1976: Thermodynamic Limitations in Organic Acid/Carbonate Systems, *JPT.*

Durak S.,Erkan B.,Aksoy N., 1993: Calcite Removal from Wellbores at Kızıldere Geothermal Field, *Proc. 15th N.Z. Geoth. W.shop.*

Economides M.J., Nolte K.G., 1987: Reservoir Stimulation, *Schlumberger Educational Services*, pp 16-3, Tex.

Nierode D.E., Kruk K.F., 1973: An Evaluation of Acid Fluid Loss, Additives, Retarded Acids and Acidized Fracture Conductivities, *SPE* 4549.

Özkan M.: Report, 1987: MTA, Ankara.

Satman A., Serpen U., Ugur Z., Türkmen N., 1996: Kızıldere Rezervuarında Tekrar Basma Uygulamasının Önemi, *11th Turkish Petroleum Congress.*

Serpen U., Gülgör A., Alpkaya E.N., 1995: Well Kogging Applications in Geothermal Wells, *Turkish Journal of oil and Gas,* Cilt:1 Sayı:1.

Serpen, U., Satman, A., Kasap, I., 1998: Assessment of Well Testing in Kizildere Geothermal Field, *GRC Annual Meeting*, San Diego.

Squire, D.P., Smith D.A., Dougherty E.L., 1962: *JPT,* 14 , pp.436.

Terrill R.M, 1965: International Journal of Heat and Mass Transfer, 8,pp.1491.