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Successful stimulation of geothermal wells through hybrid acidizing techniques

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ABSTRACT

Mexico, the world's fourth largest producer of geothermal energy, generates 965 megawatts (MW) of electricity. This production comes from a number of different fields,although the Cerro Prieto field alone produces 720 MW. However to maximize the steam production it is often necessary to perform acid stimulation treatments. The temperature and mineralogy of the naturally fractured volcanic formations and scaling tendency of the produced water present some unique challenges.

The potential of many geothermal wells is limited by formation damage. Drilling fluid invasion, fines migration, silica plugging, and scaling being the most common. For this reason characterization of the formation mineralogy in the producing wells is key to stimulating the wells and improving the production of steam.

Mineral scale deposition occurs in the wellbore or in the natural fractures through which water is either injected or produced. In producing wells, the composition of scale is dependent on the mineralogy of the metamorphic formation. In injection wells, the scale is dependent on the composition of the injected water. With limited information regarding the mineralogy of the scale and the formation, many conventional matrix treatments are unsuccessful.

To address the challenges of stimulating volcanic formation, a hybrid design methodology combining sandstone and carbonate acidizing techniques has proved to be successful in treating geothermal wells The treatments are further customized for each field to account for the differences in the mineralogy. The final fluid composition is often very different from that used to treat conventional sandstone and carbonate reservoirs.

The hybrid design methodology has been successfully used to stimulate more than 20 wells in Mexico in a number of different fields including Los Humeros (Puebla), Cerro Prieto and Tres Vírgenes (Baja California), and Azufres (Michoacán). The results of these campaigns demonstrate that it is possible to consistently improve the productivity of geothermal wells and fluid admission of injectors through the use of a correctly designed treatment

INTRODUCTION

Whenever a field is stimulated for the first time there is always a lot of information that is not available to optimize the treatment design.

Volcanic rock can be considered as burnt sandstone, which when subjected to high temperatures and pressure converts into amorphic minerals that are only slightly soluble in hydrofluoric acid (HF). Steam and super-saturated hot water in the natural fissure network present in these formations results in mineral scale deposition. These fissures and the associated damage is the reason why some of the techniques used to stimulate naturally fractured carbonate formations can be applied in these volcanic formations.

The principle problem in geothermal wells is the very high temperature which typically is between 250 degC and 300 degC. This means that prior to working in these wells it is necessary to cooling down the formation.

FIELD DESCRIPTION

GEOLOGY OF THE GEOTHERMAL FIELDS IN MEXICO IS WELL DOCUMENTED IN THE LITERATURE. WHAT FOLLOWS IS A BRIEF DESCRIPTION OF THE FIELDS WHERE ACID TREATMENT WERE PERFORMED (FIG. 1).

Fig. 1—Geographical location of Mexican geothermal fields

Cerro Prieto field

Cerro Prieto is the oldest and largest active Mexican geothermal field. It is located in the northern part of Mexico, in Baja California State. This geothermal field lies in a pull-apart basin originated between two active strike-slip faults (the Cerro Prieto and Imperial faults) belonging to the San Andres Fault System. Thinning of the continental crust in the basin has produced a thermal anomaly that is the heat source of the geothermal system (Herrera 2005; Barrios et al. 2012).

The geothermal fluids are contained in sedimentary rocks (lenticular sandstones intercalated in a series of shales) with a mean thickness of 2,400 m. More than 350 geothermal wells have been drilled in 35 years in Cerro Prieto, with depths up to 4,400 m^2. Cerro Prieto field generates an average of 720 MW.

Las Tres Vírgenes field

Las Tres Vírgenes field located in the middle of the Baja California peninsula, at the north of the state of Baja California Sur and inside the buffer zone of the El Vizcaino Biosphere Reserve. Las Tres Vírgenes is inside a Quaternary volcanic complex composed of three N-S aligned volcanoes, hence the name of the field.

The geothermal fluids are hosted by intrusive rocks (chiefly granodiorite) and the heat source of the system is related to the magma chamber of "La Vírgen" volcano, the youngest and most southern of the three volcanos (Portugal et al. 2000) . The average production for Tres Vírgenes field is 10 MW (Jaimes-Maldonado and Sánchez-Velasco 2003).

Los Azufres field

This field is located in the state of Michoacán, approximately 300 Km from Mexico City. The field is situated in volcanically active area, 2500 meters above sea level. The reservoirs are composed mainly of volcanic rocks with in some cases is more than 20% carbonates. The geothermal fluids are present in andesite which is intersected by three fault systems produced by local and regional tectonic activity. The fault systems present an E-W trend and this feature controls the movement of the subsurface fluids. The heat source of the system appears to be related to the magma chamber of the nearby San Andrés volcano that is the highest peak in the area (Torres-Rodríguez et al. 2005)

These reservoirs are characterized for being naturally fractured with the fractures filled with the same volcanic rock. The older wells in this field were damaged while being drilled due to the invasion of drilling fluid and deposition of solids in the natural fractures (Armenta et al. 2012). Damage from plugged perforations and debris from perforating (Flores et al. 2011) is also common.

Since these wells produce steam from an active volcanic, the bottomhole temperatures are very high compared to those present in oil wells. The average temperature is between 250 and 280 °C (482 – 536 °F). The wells drilled in this field are vertical or slightly deviated, with a depth around 2,000 meters. The average production for Los Azufres is 195 MW.

Los Humeros field

Los Humeros geothermal deposit is located in the eastern part of central Mexico approximately 25 km northwest of Perote city in the State of Puebla, 200 km to the east of Mexico City and is inside the Plioquaternary volcanic caldera complex which is less than 500,000 years old. This complex is located in the eastern part oyyhuj f the Mexican Volcanic belt (Gutierrez-Negrin, et al. 2010; Cedillo. 2000).

The geothermal fluids are contained in andesite overlying a complex basement composed of metamorphic, sedimentary and intrusive rocks (Arellano et al. 2003). The heat source is a magma chamber that has collapsed twice forming the Los Humeros and Los Potreros calderas, the latter nested in the first. The average production for Los Humeros is 40 MW.

GEOTHERMAL STIMULATION WORKFLOW

Geothermal wells are the conduits to take geothermal fluids, which are brine and steam, to the surface where these fluids are separated in order to have steam to drive thermoelectric turbines. These wells are drilled using the same techniques as used to drill conventional oil wells of a similar depth.

The energy/steam production of each geothermal well is also analyzed with the objective of identifying any abnormal behavior. As for an oil well lower than expected production is usually an indication that the well is damaged. In this case the proper evaluation must be done to determine whether it is a candidate for a matrix or hydraulic fracturing treatment. This evaluation will lead to the correct treatment design, fluid optimization and preparation of the well prior to any stimulation treatment.

Geothermal wells, present several challenges, such as, the use of the correct corrosion inhibitors, avoiding secondary or tertiary reactions/precipitations and fluid diversion to ensure optimal zonal coverage. The geological setting and dynamic reservoir response also plays an important role in order to determine optimum treatment design. The analysis previously mentioned can be summarized in the workflow shown in Figure 2 that describes the overall process to stimulate a geothermal well.

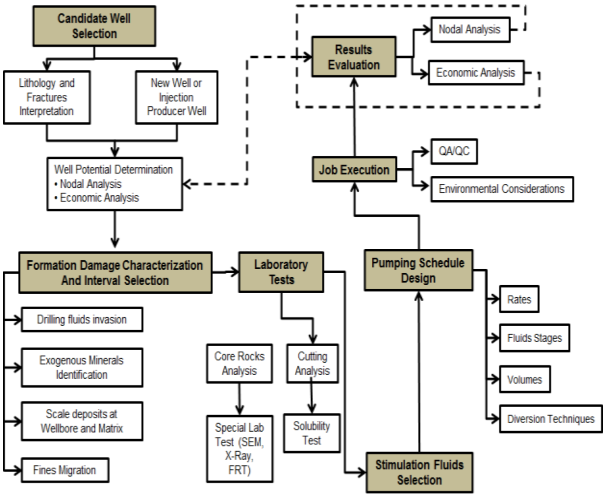

Fig 2—Geothermal wells stimulation workflow

Candidate Well Selection

New wells will have a very different production performance compared to existing wells. However, in both cases it is not uncommon for the production to less than expected. In which case is important to take into consideration:

a. A thorough analysis of the lithology and an evaluation of the natural fractures to determine if they are open closed or plugged. It is very common when drilling a geothermal well with water based fluid that total losses occur when drilling the 'reservoir' section. As a consequence the lithology cannot be determined by cuttings. Therefore different tools such as borehole textural analysis must be used.

b. High pumping pressure and corrosive fluids can eventually compromise the execution of the treatment and in the worst case scenario the integrity of the well. Therefore this should be taken in account prior to any treatment

c. The matrix permeability of the formation and the natural fissures present must be analyzed to determine their contribution to the movement of the geothermal fluids in the reservoir.

One important difference between a new well and an old well is that for the new well there is no production history and care must be taken to have a realistic production forecast. In the case of existing wells the history production will allow for the identification of any unusual behavior. The detection of changes in the production greatly help to identify candidates for stimulation treatments.

Finally an economic analysis is required to support the production forecast. This economic analysis needs to include nodal analysis and production decline curve analysis.

Formation Damage Characterization and Interval Selection

When drilling permeable, porous and naturally fractured formations drilling fluid invasion damages the formation. For this reason the most damage often occurs in the most potentially productive intervals. Meanwhile, producing wells are often progressively damaged (Aguilar et al. 2012) by minerals filling the pore throats or the fissure network, fines migration (You et al. 2013) and scale deposits in both the wellbore and formation matrix.

Selecting the correct interval(s) to treat is also extremely important. Pressure and Temperature (P-T) logs can be used to identify the most prolific producing zones. On new and existing wells, the measurement of temperature gradient and its deviation from normal geothermal gradient will be an indication of those intervals producing water vapor. Another option can be an injection test, observing the cool down and heat up across the intervals of interest in addition to the injection pressure response. Real time data acquisition, using fiber optics and coil tubing in the future may help to optimize the treatment design, either during the treatment or in the post-treatment evaluation. However, at the present time the use of fiber optics is limited by the temperature rating of the fiber. The change in the temperature profile, observed in the Figure 3, is an indicator of the area with the highest heat exchange capacity.

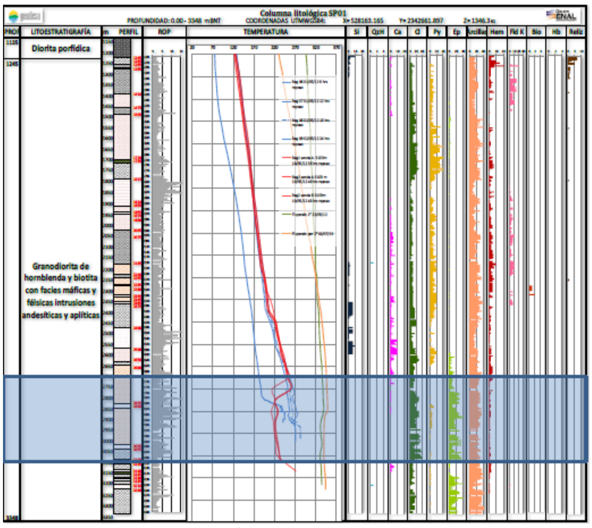

Fig. 3—Temperature profile and gradient

Laboratory Testing and Fluid Selection

Matrix stimulation treatments in volcanic geothermal reservoirs are generally similar to treatments performed in conventional oil and gas sandstone reservoir. However, volcanic formations frequently have much higher carbonate content than conventional sandstones. In fact, the presence of natural fractures and carbonate has led several authors to highlight the similarities between treating geothermal wells and naturally fractured carbonate oil and gas producers. However, the natural fractures may also be filled with silica, which has very limited solubility in acid. The need to be able to dissolve both carbonates and silica is the driver behind what is referred to as the hybrid stimulation technique, using hydrochloric acid (HCl) and hydrofluoric acid (HF) as the main treating fluids.

As in conventional sandstone acidizing an HCl pre-flush is pumped to dissolve any carbonate present and so avoid any precipitation of calcium fluoride from HF acid reacting with the carbonates. However, removing the carbonate scale from the natural fractures may be sufficient to effectively stimulate the well.

The selection of the main treatment fluids is based on the formation mineralogy, characterization of the formation damage and laboratory testing. A number of different HCl-HF formulations were evaluated, although, the previous stimulation campaigns in Mexico had used 10% HCl, 10% HCl- 5% HF and 12% HCL- 3% HF (Flores-Armenta and Ramirez-Montes, 2010; Montalvo et al. 2012). In addition several other acid systems were tested, HCl, organic fluoboric acid, formic acid, acetic acid, citric acid and systems based on chelating agents (Mella et al. 2006). However, in many cases the high cost of chelants limit their use for stimulating geothermal wells.

A 10% HCl over-flush is pumped with the objective of increasing the penetration of the treating fluids and ensuring that reaction products that may precipitate do so at some distance from the wellbore.

The process of evaluating different stimulation fluids must be supported through different tests. Whenever core samples are available a complete analysis of them should be performed in order to identify main matrix characteristics, including rock porosity, permeability, mineralogy, presence of fissures and filling materials of the pore throats of the natural fissures. When cutting samples are available solubility tests under bottomhole temperature conditions must be performed evaluating the performance of each stimulation fluid.

Table 1 shows the solubility of formation cuttings, with different acid systems.

TABLE 1—FORMATION SOLUBILITY

Depth (m)	Solubility (%)			
	System 1	System 2	System 3	Hybrid System
1,414	65.93	58.88	8.28	**69.16**
1,417	59.68	36.98	5.64	**63.11**
1,420	56.67	44.38	7.54	**61.86**
1,423	58.74	43.23	5.67	**63.03**
1,433	66.71	59.02	8.29	**69.64**
1,439	65.61	X	X	**70.09**
1,442	71.63	59.33	5.01	**75.15**
1,445	71.94	57.96	4.35	**76.87**
1,448	72.34	X	X	**77.54**
1,451	70.52	56.44	X	**77.55**
1,527	66.33	X	X	**70.95**
1,530	66.17	55.70	X	**69.65**
1,533	69.62	51.98	5.81	**72.59**
1,554	73.14	58.66	5.69	**78.77**
1,558	69.48	61.58	4.85	**71.56**
1,561	68.14	55.65	5.21	**74.93**
1,564	65.21	48.29	8.80	**73.35**
1,618	58.99	53.01	5.45	**63.07**
1,622	63.98	51.30	5.34	**66.99**
1,625	61.93	X	X	**68.94**
1,628	69.64	53.37	6.08	**79.65**
1,631	68.43	X	X	**X**
1,692	61.85	32.56	6.01	**67.29**
1,695	58.49	31.22	5.67	**62.10**
1,698	64.59	30.37	4.65	**70.36**
1,701	56.61	30.88	8.22	**63.24**

Based on the solubility results and the analysis of each geothermal well performance optimal fluid composition was determined; these solubility tests were performed with cuttings samples from Mexican geothermal fields. The solubility test results allowed to develop a treatment fluid conformed by a mixture of HCl and HF in specific combination and concentrations.

Treatment Design

Once the stimulation fluids are selected the pumping schedule needs to be designed with the objective of optimizing the pumping rates and the volume of each fluid system. Different scenarios can be generated and simulated to obtain the most effective reservoir penetration. The skin evolution simulation will help to determine the optimal total treatment and stages volumes in conjunction with the economic analysis; the forecast post-treatment production will support the evaluation of the production results vs the economic indicators.

Based on the previous experience from the stimulating wells in Mexico and Central America it was possible to develop some guideline, in order to define the acid systems and volumes required. In every case the treatment is displaced a minimum of 5 ft. from the wellbore with water.

HCl solubility less than 6%:
- Preflush: 50 to 75 gal/ft. of HCl.
- Main Fluid: 75 to 100 gal/ft. of HCl-HF.
- Overflush: HCl gal/ft. Ammonium Chloride

HCl solubility between 6 and 20%:
- Preflush: 150 to 200 gal/ft of HCl.
- Main Fluid: 75 to 100 gal/ft of HCl-HF.
- Overflush: HCl gal/ft Ammonium Chlorite

HCl solubility greater than 20%:
- Main Fluid: 75 to 150 gal/ft. of HCl.
- Overflush: HCl gal/ft. Ammonium Chloride

The use of diverting agents will take importance whenever the zone of interest shows a clear permeability contrast or when its height is longer than 50 meters. In specific cases where the objective is to ensure a complete coverage of the zone of interest the acid treatment can be performed through coiled tubing; this will allow injecting the fluid systems at very specific depths but probably the pumping rate will be limited based on tubing diameters. This also should be evaluated comparing skin evolution vs post-treatment forecast.

Figure 4 and 5**,** show the treatment plots for two geothermal wells where the hybrid acid technique was applied. Figure 4 corresponds to an acid fracturing treatment where the maximum pumping rate was 60 bpm. Figure 5 shows an acid treatment performed through CT with a maximum pumping rate of 11 bpm.

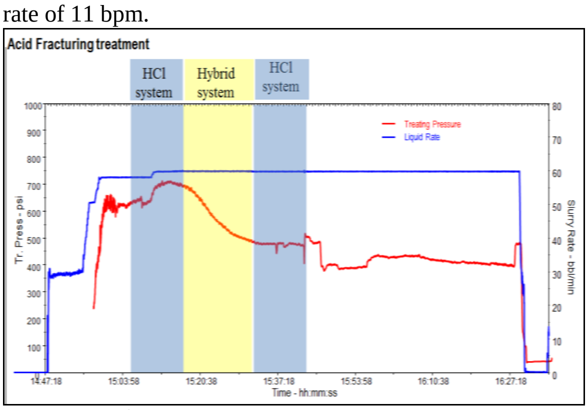

Fig. 4—Acid fracturing treatment plot

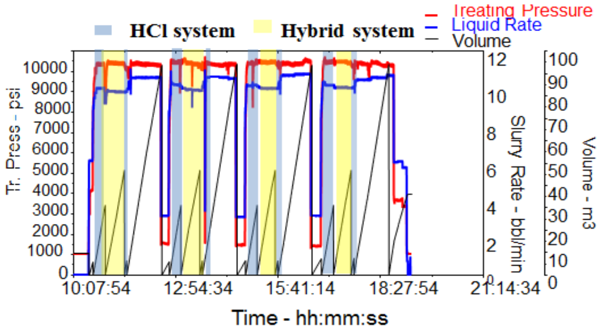

Fig. 5—Acid treatment through CT plot

Table 2 and 3, show pumping schedules for hybrid acid technique. Table 2 corresponds to and acid fracturing treatment schedule. Table 3 shows the schedule for a job pumped through CT.

TABLE 2— ACID FRACTURING PUMPING SCHEDULE

Acid Fracturing Schedule						
Stage	Fluid	Rate (bbl/min)	Vol Liq (m3)	Vol Liq (bbl)	Time (min)	Comments
1	HCl 15%	60	155	975	16.25	Pre Flush
2	HCl-HF 10:5	60	235	1479	24.7	Main Fluid
3	HCl 15%	60	32.5	205	3.4	Post Flush
4	Water	60	470	2957	49.3	Over Flush

TABLE 3 — CT STIMULATION PUMPING SCHEDULE

CT Stimulation Schedule						
Stage	Fluid	Rate (bbl/min)	Vol Liq (m3)	Vol Liq (bbl)	Time (min)	Comments
1	water	3	52	328	109.3	Lowering CT
Zone 1 Stimulation						
2	water	8	6	38	4.8	Inyection Test
3	HCl 15%	8	31	195	24.4	Pre Flush
4	HCl-HF 10:5	8	47	296	37.0	Main Fluid
5	HCl 15%	8	6.5	41	5.1	Post Flush
6	Water	8	94	592	74.0	Over Flush
7	Water	8	10.2	65	8.1	Lowering CT
Zone 2 Stimulation						
8	HCl 15%	8	31	195	24.4	Pre Flush
9	HCl-HF 10:5	8	47	296	37.0	Main Fluid
10	HCl 15%	8	6.5	41	5.1	Post Flush
11	Water	8	94	592	74.0	Over Flush
12	Water	8	10.2	65	8.1	Lowering CT
Zone 3 Stimulation						
13	HCl 15%	8	31	195	24.4	Pre Flush
14	HCl-HF 10:5	8	47	296	37.0	Main Fluid
15	HCl 15%	8	6.5	41	5.1	Post Flush
16	Water	8	94	592	74.0	Over Flush
17	Water	8	10.2	65	8.1	Lowering CT
Zone 4 Stimulation						
18	HCl 15%	8	31	195	24.4	Pre Flush
19	HCl-HF 10:5	8	47	296	37.0	Main Fluid
20	HCl 15%	8	6.5	41	5.1	Post Flush
21	Water	8	94	592	74.0	Over Flush
Run Out of Hole						
22	Water	8	10.2	65	8.1	CT to surface

RESULTS

Figures 6 and 7, show the production history of two wells and the increased production after acid stimulation treatments. The extended period of stable production after the treatments indicates that the acid treatments were properly designed and executed.

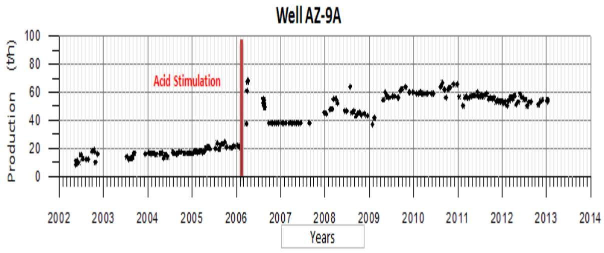

Fig. 6—Well AZ-9A production history

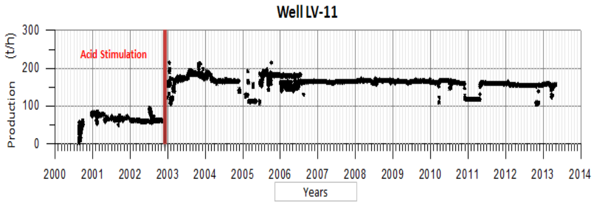

Fig. 7—Well LV-11 production history

Table 4 shows the production data after matrix stimulations treatments performed using the hybrid acidizing technique. The treatments were either bullheaded or pumped through coiled tubing. After almost all the treatments there was a significant increase in both the production of steam and wellhead pressure.

In addition during 2012 and 2013 three acid fracturing treatments were performed with pump rates of 60 bpm. The results of are shown in the Table 5. The treatments did not achieve the hoped for increase in production. This is most likely due to the fact that the candidate wells had poorly developed natural fractures which in in some cases may be plugged with silica.

TABLE 4—POST- MATRIX STIMULATION RESULTS

Well	Year	Diagnostic	Drilling Mud Lost (m3)	Pumped Through	Production Capacity			Increase/Improvement	
					Original (t/h)	Pre-acid (t/h)	Post-acid (t/h)	Vs Original (%)	Vs Pre-acid (%)
AZ-9AD	2005	Bentonitic mud damage	1326	Drill Pipe	22	22	68	209%	209%
AZ-9A	2006	Bentonitic mud damage	505	Drill Pipe	15	25	67	347%	168%
AZ-56R	2006	Bentonitic mud damage	10921	Drill Pipe	15	15	70	367%	367%
AZ-25	2008	Silica incrustation	-	CT	40	16	30	-	88%
AZ-68D	2008	Bentonitic mud damage	8238	CT	10	10	64	540%	540%
AZ-57	2010	Silica incrustation	-	CT	25	15	20	-	33%
AZ-36	2010	Silica incrustation	-	CT	44	15	35	-	133%
Az-51	2010	Silica incrustation	-	CT	37	17	42	13%	147%
Az-30	2012	Bentonitic mud damage	-	CT	16	13	23	43%	76%
H-01D*	2010	Silica and calcite incrustation	-	Drill Pipe	42	6	45	7%	650%
LV-13	2002	Silica and calcite incrustation	5583	CT	0	0	21	100%	100%
LV-11	2002	Bentonitic mud damage	5119	CT	12	12	35	192%	192%
LV-04	2004	Calcite incrustation	-	CT	32	9	42	31%	367%
LV-13	2004	Calcite incrustation	-	CT	21	14	28	33%	100%
LV-4A	2007	Bentonitic mud damage	2700	CT	0	0	20	100%	100%
LV-13D	2007	Bentonitic mud damage	1326	CT	0	0	20	100%	100%
LV-13D	2012	Calcite incrustation	1326	CT	0	6	13	100%	100%
LV-4A	2012	Calcite incrustation	2700	CT	0	11	13	100%	9%
CP-307	2010	Bentonitic mud damage	-	CT	55	12	32	-	166%
CP-208	2010	Bentonitic mud damage	-	CT	70	0	42	-	100%

TABLE 5—POST-ACID FRACTURING RESULTS

Well	Year	Diagnostic	Lost Drilling Mud (m3)	Pumped Through	Rate (bpm)	Production Capacity			Increase / Improvement	
						Original (t/h)	Pre-acid (t/h)	Post-acid (t/h)	Vs Original (%)	Vs Pre-acid (%)
H-41	2012	Low perm	-	Tree Saver	30	15	15	20	25	25
AZ-47D	2013	Low perm	601	Tree Saver	60	0	0	30	100	100
AZ-1D	2013	Low perm		Tree Saver	60	0	0	12	100	100

Table 6 summarizes the results obtained in each of the fields where the hybrid stimulation technique has been applied. The average steam production increased 2 -3 times after each stimulation campaign. The savings as a result of the increased production and injection capacity is equivalent to the cost of more than 10 new production wells (Flores-Armenta and Ramirez-Montes, 2010)

TABLE 6— OVERALL INCREASE IN PRODUCTION

Field	Period	Number of treated wells	Success Rate (%)	Pumped Through	Production Capacity			Increase / Improvement	
					Original (t/h)	Pre-acid (t/h)	Post-acid (t/h)	Vs Original (%)	Vs Pre-acid (%)
Azufres	2000-2013	10	90	Drill Pipe/CT	230	154	419	82	172
Tres Virgenes	2002-2007	9	88	CT	90	52	189	110	263
Los Humeros	2010-2012	3	66	CT	65	29	65	------	124
Cerro Prieto	2010-2013	10	100	Drill Pipe/CT	--------	50	255	------	410
Average					128	71	232	81	226
TOTAL					**385**	**285**	**928**	**141**	**225**

CONCLUSIONS

The steam production of geothermal wells often decreases with time due to the natural fractures and fissures becoming plugged with mineral deposits.

The most common mineral deposits in the natural fractures and wellbore are calcite and silica.

The use of hydrochloric acid and hydrofluoric acid systems has proved effective in stimulating the production of steam.

Stimulating geothermal wells is a cost effective way to maintain production and so minimize the cost of drilling new wells.

Low rate matrix treatments have proved to be more economically successful than high rate acid fracturing treatments.

No two geothermal fields are the same and the treatments and treating fluids need to be adapted for each field.

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SI Metric Conversion Factors

bbl	×	1.589 873	E-01 = m^3
ft	×	3.048*	E-01 = m
°F		(°F-32)/1.8	= °C
in.	×	2.54*	E+00 = cm
lbm	×	4.535 924	E-01 = kg
lbm/bbl	×	2.853	E+00 = kg/m^3
psi	×	6.894 757	E+00 = kPa
MW	×	2.39085	E-05 = cal/sec

*Conversion factor is exact.