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HOW MUCH STIMULATION CAN WE AFFORD?

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Unexpected, low production rates in a geothermal well can occur due to several causes: e.g. formation damage, completion effects or lack of connectivity to main fluid conduits. Stimulation treatments have been successfully applied in many cases to increase the well production rate to commercial levels. These stimulation techniques were originally developed to address similar problems in oil and gas production wells. The applicability of these stimulation techniques to a high temperature, naturally-fractured reservoir is less well known. This is particularly relevant since oil and gas field experience has shown that fractured formations have often proven to be one of the most difficult well types to treat. This paper addresses the twin questions of whether stimulation technology can be successfully applied: a) technically, to the high temperature environment of naturally fractured geothermal wells and b) commercially, to the different financial environment of the geothermal industry compared to that of the oilfield. The paper provides a comparative, techno-economic study of three well stimulation techniques (matrix acidizing, hydraulic fracturing and thermal fracturing) within the technical and economic environments of Comisión Federal de Electricidad in México, with special focus in matrix acidizing, since it is the technique that more real applications has had in Mexico.

1. INTRODUCTION

A geothermal resource is quite different from an oil or gas reservoir or even a ground water reservoir. In an oil reservoir, once the oil has been extracted, the reservoir is exhausted. By contrast, in a geothermal reservoir the water or steam originally present in the reservoir can be replaced by surrounding cooler water that is heated by the reservoir rock, becoming available for additional production (O’Sullivan and McKibbin, 1993). Despite all the differences between hydrocarbon and geothermal reservoirs, the techniques used for extraction of fluids are very similar; as are the exploration techniques and reservoir management approaches.

Like in an oil prospect, the key issue in a geothermal development is the ability to reach rock with sufficient flow and storage capacity that can produce fluids with sufficient energy that they drive a surface turbine to generate electricity for a long enough time period that the project is economically viable. Techniques similar to those used in the oil industry are employed to drill and complete well in the productive reservoir. In both cases formation damage should be minimized in order to optimize well performance and, in our case, maximize power generation at the surface.

The economic climate, and the reduced levels of investment in geothermal wells necessary to maintain project profitability, is very different between the two cases. This is due to the large differences in specific energy content and price of a given volume of oil and a similar quantity of steam. This, together with the highly consolidated nature of the rock, is one of the reasons why geothermal wells are frequently completed using slotted liners or open holes. Drilling is normally performed using cheap, bentonitic mud, sometimes even in the reservoir zone, for the same reason. Geothermal reservoirs are characterized by a large degree of fracturing even when they occur in sedimentary rocks with intergranular porosity (Aguilera, 1995). The presence of such fractures is often first recognized by the sudden occurrence of large volume mud loss during drilling. Such losses to the natural fracture network have the potential to inflict large-scale formation damage with a consequent significant reduction in steam production. A well may encounter multiple, widely spaced, fracture zones, resulting in flow rates that are too low. Depending on the geological environment, the well may only contact a matrix formation of insufficient permeability. Stimulation techniques have the potential to remediate such causes for low flow-rate wells. In the first case, the damage due to mud invasion into open fractures, and the pores or minor flow channels present in the host rock, can be reduced with an acid job. Low productivity due to lack of communication with the naturally occurring, main conduits for fluid flow can be improved by thermal and /or hydraulic propped fracturing of the wells. These types of stimulation can make the difference between a productive or an abandoned well (Flores et al., 2005).

2. WELL STIMULATION TECHNIQUES REVIEW

Matrix acidizing, hydraulic fracturing and thermal fracturing have been analysed for their applicability to geothermal environments (Table 1).

TABLE 1: Applicability of stimulation techniques to geothermal environments (Flores et al., 2005)

Stimulation Technique	Description	Applicability to Geothermal Wells
Matrix acidizing*	Injection of acids below fracture propagation pressure to remove permeability damage within the fracture or the near wellbore area.	Reduced acid reaction required? Avoid corrosion of well construction materials. Treatment of selected, smaller intervals requires use of diverters.
Hydraulic fracturing*	Fluids pumped at high pressure and rate so that formation fracture propagation pressure exceeded. Place proppant to maintain created fracture flow capacity.	High quality, small proppant grain size may be required. Resin coated materials. Treat short fracture interval (economics). Standard liner completion not preferred
Thermal fracturing*	Injection of cool water into a hot formation to reduce the thermal stresses sufficiently to create new fracture flow channels.	“Rule-of-thumb” experience based techniques only. No soundly based, treatment design methodology available.

*Use scale inhibitors to prevent scale precipitation in the newly formed flow channels is an issue common to all methods if large volumes of water injected.

2.1 Matrix acidizing

Matrix acidizing is used to remove near wellbore permeability damage with the objective of restoring the well to its natural undamaged inflow performance. This (chemical) treatment involves injection of a reactive fluid, normally an acid, into the porous medium at a pressure below the fracturing pressure (Economides and Nolte, 1987). The acid works through a process of dissolution of (foreign) materials deposited within the porous formation, such as carbonates, metallic oxides, sulphates, sulphides or chlorides, amorphous silica, drilling mud and cement filtrates from invasion (Davies, 2003). A second type of acid stimulation and perhaps the most common one for geothermal environments is the cleaning of (pre-existing) fractures. The intention is for the acid to dissolve (or mobilize sufficiently that they can be removed by later flow processes) either foreign or original fracture-blocking material. Treatment volumes, injection rates, acid placement techniques, acid system selection and evaluation of the results when stimulating geothermal wells all follow the same criteria as for oil wells. The important difference is the formation temperature. High temperatures reduce the efficiency of corrosion inhibitors (and increase their cost) as well as increasing the acid/rock reaction rate. The high acid rock reaction rate requires the use of a retarded acid system to ensure acid will not all be spent immediately next to the wellbore, but will penetrate deeper into the formation. Cooling the target formation by injecting a water preflush will reduce the temperature and the acid reaction rate.

Protecting the tubulars against corrosion is another serious challenge. This requires careful selection of acid fluids and inhibitors (Buijse et al., 2000), while cooling the well by injecting large volume water preflush may reduce the severity of the problem.

2.2 Hydraulic fracturing

A propped, hydraulic fracturing treatment is performed by pumping specially engineered fluids at sufficiently high pressure into the interval to be treated so that an (often vertical) fracture is opened. Connection of many, pre-existing fractures and flow pathways within the reservoir rock with a larger fracture may be achieved. The final stage of the treatment is the injection of a proppant (usually sand) slurry. This proppant maintains the created fracture flow capacity after relaxation of the hydraulic pressure. The published literature contains only a limited number of successful cases when fracturing high temperature formations. That is probably because hydraulic fracturing of high temperature, naturally-fractured formations places severe demands on the fluid and proppant selection. These include (Entingh, 2000):

- Thermal degradation of fluid viscosifying polymers and cross-linkers preventing effective growth and propping of the hydraulic fractures;
- Excessive fluid leak-off leading to early screen-out and creation of a fracture of inadequate length;
- Degradation of proppant by the highly saline produced fluid.

Limited research, specifically for geothermal wells, has been reported, although work targeted at fracturing high-temperature oil and gas reservoirs has suggested the following guidelines:

- Small proppant grain size (20/40 or 30/50 mesh Bauxite) show better performance;
- Maximise pump rate and reduce treatment time by using large tubing sizes and higher wellhead pressures;
- Increase fluid viscosity by using higher gel loadings.

It is conventional geothermal practice to complete wells using slotted liners over intervals as long as 1000 m. Hydraulic fracturing treatments in such environments become very difficult due to the impossibility of controlling the point of fracture initiation. The technical and economic implications of a change of the well completion design to a cemented and perforated casing should be analysed in detail.

2.3 Thermal fracturing

Thermal fracturing is a stimulation phenomenon that occurs when a fluid (e.g. produced water, seawater, aquifer water or surface water), considerably colder than the receiving hot formation, is injected. Injection of the cooler water leads to thermal contraction of the reservoir rock in the region near the injection well, reducing the stresses. The reservoir can be fractured at a significantly lower pressure than the original, in situ stress would indicate, when there is a large temperature contrast between injected water and the formation (Slevinsky, 2002). The occurrence of thermal fracturing during cold-water injection into porous and permeable classic formations is well documented. Suitable rock-mechanical process models have been developed for treatment control and optimization.

The process is less well documented in geothermal production wells. Tulinius et al. (2000) report thermal fracturing of such a geothermal well in Guadeloupe in France. A 253°C reservoir was stimulated using seawater mixed with an inhibitor to prevent anhydrite scaling. Production results showed an output increase of 50% compared with original production flow rate. The enhanced production rate made the well sufficiently economically successful that it was still flowing to an existing power plant one year after the treatment.

Thermal fracturing will not always be a technically suitable solution – for example, if it is required to dissolve material that is blocking the flow of steam e.g. a scale. However, thermal fracturing is very attractive compared to the other options for cases when flow can be restored by the generation of a (relatively) near wellbore fracture network that will (hopefully) reconnect to a main reservoir flow system. The fluids used during Thermal Fracturing are characterised by:

- Benign compared to aggressive acids;
- Easy-to-prepare fluid with simple chemistry, especially when compared to a fully-formulated, high temperature, cross-linked fracturing fluid;
- Requires mobilization of a minimum of equipment;
- High pump pressures not normally required;
- Treatment fluids present minimal Health, Safety & Environmental issues;
- Low Cost.

Fracture closure is frequently cited as a cause of concern when designing a thermal fracturing treatment, though the productive flow channel had clearly remained open in the case above. Producing the treated well will increase the temperature of the cooled zone, with a consequent restoration of the previous rock stress. This would be expected to reduce the gain in flow capacity, since proppant is not present to keep the fracture open after the treatment. Although strain changes in the rock appear to be controlling the remaining increased permeability, there are no single models that describe the fundamentals of this process, even though several studies has been done in order to develop EGS systems around the world.

3. STIMULATION RESULTS IN MEXICO

The first matrix acidizing job in Mexico was performed at the Los Azufres Geothermal field in 2000. The Los Azufres geothermal field is located in the northern portion of the Transmexican volcanic belt, 80 km east of Morelia city and 250 km east of Mexico City. It is a heavily fractured and faulted volcanic hydrothermal system, located in a sierra at an average elevation of about 2800 m. It is located in a forest area with abundant vegetation, which is considered a forest reservation zone (Torres-Rodriguez et al., 2000). At that time, there were many questions to solve and the technique was only applied in two injection wells. The results were not very surprising, mainly because the treatment flow rates and chemical composition were very low.

Three more years were needed to apply a better technique in production wells, now applying the flow rates and acid mixtures that were used in the Philippines at that time (Bunning et al., 1995 and Yglopaz, 2000). A second attempt was made at Las Tres Vírgenes Geothermal Field, a granite type reservoir where a high skin factor and a resulting marginal steam flow rate and wellhead pressure were identified in the two production wells (Jaimes et al., 2003). The results were encouraging, showing production increases of up 367%. Since that date, several acidizing jobs have been performed at the Los Azufres and Las Tres Vírgenes geothermal fields, and a couple of attempts had been done at Cerro Prieto and Los Humeros.

In general the acid treatment design for the wells was performed with the following criteria: wells damaged with calcite scaling are treated using the same concentration for the pre- and post-flush operations, while the main flush was settled in 12% HCL- 3% HF.

With the exception of well LV-3, all wells damaged with bentonitic mud or scaled with amorphous silica during their commercial operation were treated using a pre- and post-flush concentration of 10% HCl, a main flush of mud acid (10% HCL- 5% HF), and an over-flush with geothermal water. A higher concentration of HF was used to accommodate the significant amount of mud lost in the formation. Injection of the main acid was preceded by a pre-flush solution of 10% HCl to dissolve the iron and carbonate materials that may later deposit insoluble minerals (e.g. CaF_2) with the HF acid and will serve as a spacer between the main flush and the formation brine.

In all cases, a volumetric flow rate of 75 gallons of main flush acid per foot of payzone interval was used to inject the acids into the formation, and a flow rate of 50 gallons of pre-flush volume per foot of payzone thickness was also used in the wells.

The main flush acid was followed by a small volume of 10% HCI post-flush solution to act as spacer between the main acid and formation brine and to reduce possible precipitation damage. Brine over-flush was then injected to displace the acid treatment solution and rinse the tubular and metal casings of unspent acid in the wellbore, using twice the volume of the main flush.

Corrosion inhibitors and intensifiers were also added to the acid mixtures (pre-flush, main flush and post-flush) to reduce the corrosion rate of the tubular well and equipment by the acid. Chelating or sequestering agents were also used to address iron control during acid injection. A large amount of surfactant was also added to the main flush mixtures in order to suspend the significant amount of drilling mud and minerals dissolved by the acid. Foam diversion was conducted between the payzone targets.

The pressure, flow rates and volumes observed during a typical acid job are shown in Figure 1.

Acidizing treatment statistics in México from 2000 – 2011 for production and injection wells is shown in Tables 2 (modified from Flores, 2010). As can be seen in the table, 23 of 26 acid treatments were successful in these two geothermal fields. The wells were improved by 13 – 650%, with an average improvement of 176%.

In terms of drilling savings, these acid jobs saved the equivalent of the drilling cost of 18 new production wells using an average production of 30 t/h of steam and 2 new injection wells over 11 years (modified from Flores, 2010)..

3.1 Results at the Los Azufres Geothermal Field

As mentioned before, the first two stimulations were made in the Los Azufres geothermal field in 2000 in water injection wells. As shown in Table 2, in wells AZ-7 and AZ-15 prior to the acid injection a mechanical cleaning was performed, with a gain in injection capacity, but however it was decided to stimulate the two wells obtained additional increases of 13% and 32%, respectively. In 2005 and 2008 matrix stimulations of wells AZ-8 with drill pipe and the AZ-52 coiled tubing were done and in both cases increases of more than double injection where obtained (Flores, 2010).

Nine producer wells have been matrix acidized stimulations in the Azufres (Table 3). The first treatments were made in 2005 and 2006 with a drill rig; however, in 2008 the first studies were performed with coiled tubing with very good results.

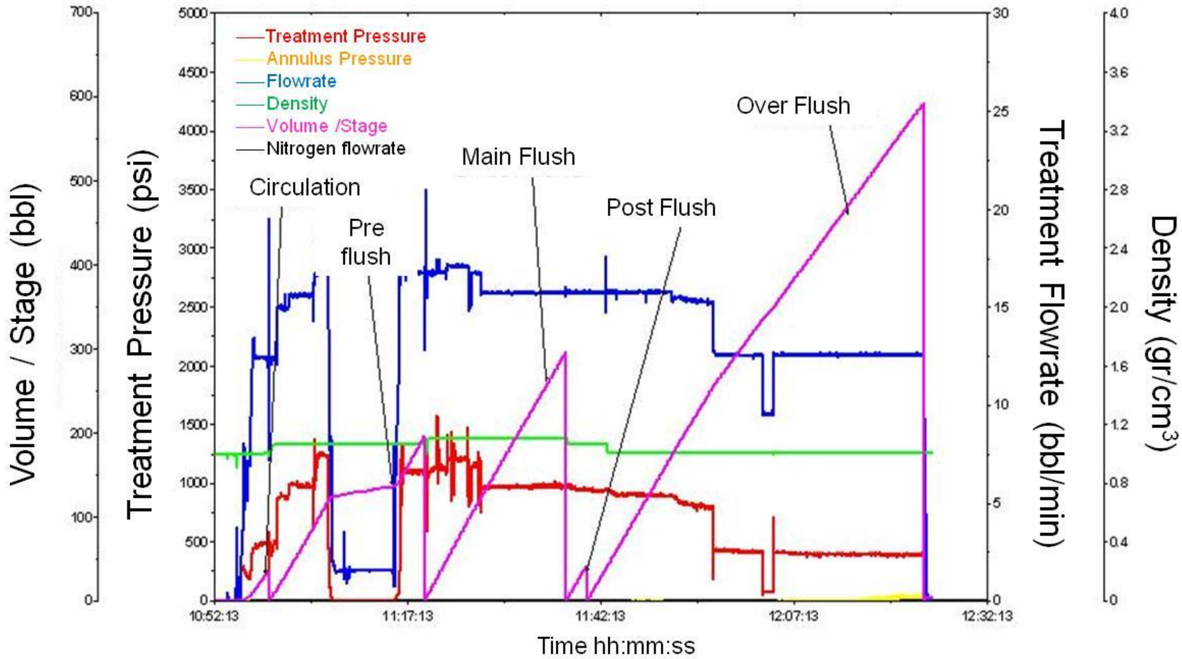

FIGURE 1: Parameter monitoring during acidizing of well AZ-9AD (Flores et al., 2006)

TABLE 2: Matrix stimulation results in injection wells at the Los Azufres geothermal field

Well Name	Year	Type of well	Type of damage	Placement technique	Injection Capacity			Improvement	
					Original (t/h)	Pre-acid (t/h)	Post-acid (t/h)	Vs Original (%)	Vs Pre-acid (%)
AZ-7*	2000	Injector	Silica Scaling	Drill pipe	600	750	850	42%	13%
AZ-15*	2000	Injector	Silica scaling	Drill pipe	350	340	450	29%	32%
AZ-8*	2005	Injector	Silica scaling	Drill pipe	290	180	410	41%	128%
AZ-52	2008	Injector	Silica scaling	Coiled tubing	350	70	170	No improvement	143%

*Wells with mechanical workover before the acid job

In 2005, the first stimulation was performed in a production well of Azufres (AZ-64) but was severely damaged by drilling fluid invasion, in which there was no improvement mainly because it was not possible to discharge the reaction products of the acid with the formation as soon as possible (Flores,2010). For the next well (AZ-9AD) logistics changed dramatically and the well tripled its production (Flores et al., 2006).

The AZ-25, a well drilled 27 years before work began, but with a history of continuous production during the last 15 years, during which it lost more than half of its production, the well was matrix stimulated in 2008 achieving an increase of 88%.

Well AZ-68D well was drilled only three years before the intervention and had not been put into production because of poor performance, however, after stimulation with acid matrix, it increased production to 64 t/h, meaning a 540% improvement.

TABLE 3: Matrix stimulation results in production wells at the Los Azufres geothermal field

Well Name	Year	Type of damage	Mud losses m3	Placement technique	Production Capacity Original (t/h)	Production Capacity Pre-acid (t/h)	Production Capacity Post-acid (t/h)	Improvement Vs Original (%)	Improvement Vs Pre-acid (%)
AZ-64	2005	Mud damage	3759	Drill pipe	6	6	0	No improvement	No improvement
AZ-9AD	2005	Mud damage	1326	Drill pipe	22	22	68	209%	209%
AZ-9D	2006	Mud damage	505	Drill pipe	15	25	67	347%	168%
AZ-56R	2006	Mud damage	10921	Drill pipe	15	15	70	367%	367%
AZ-25	2008	silica scaling	-	Coiled tubing	40	16	30	No improvement	88%
AZ-68D	2008	Mud damage	8238	Coiled tubing	10	10	64	540%	540%
AZ-57	2010	Silica scaling	-	Coiled tubing	25	15	20	No improvement	33%
AZ-36	2010	Silica scaling	-	Coiled tubing	44	15	35	No improvement	133%
Az-51	2010	Silica scaling	-	Coiled tubing	37	17	42	13%	147%

3.2 Results at the Las Tres Virgenes Geothermal Field

The first production wells that were stimulated in the Las Tres Virgenes geothermal field were LV-11 and LV-13 in 2002 (Table 4). The wells were severely damaged by drilling fluid invasion. After matrix stimulations, significant increases in production were measured (Jaimes et al., 2003).

After these, several matrix stimulations followed in years 2004, 2006 and 2007 with similar results. It is worth mentioning the case of well LV-3 where a different acid system fluid was used from previous work with lower concentration of hydrofluoric acid which showed no improvement. It is also worth mentioning that the wells LV-13, LV-4A and LV-13D were recently drilled or repaired. All these stimulations were performed through coiled tubing.

3.3 Results at the Cerro Prieto Geothermal Field

The first two acid jobs made in the Cerro Prieto geothermal field in a sedimentary environment were done in the year 2010 (Table 5). The results were positive and a new campaign for an average of 10 jobs is under bidding process. In this case, due to the geological environment and the results of the chemical analysis of petrologic samples in contact with the acids, took CFE to the decision of using low HF concentration with the main flush. In this case pre- and post-flush was 10% HCl and the main flush concentration was 9% HCl-1.5% HF.

3.4 Results at the Los Humeros Geothermal Field

This is a low permeability geothermal field in a volcanic geological environment. The first acid job was performed in the year 2010 in a severely damaged well with calcite depositions (Table 6). The results were stoning, but after 4 months flowing the well collapsed. In 2011 and 2012 acid fracture treatments were scheduled, using bull heading high pressure and high flow rate acid treatments. However the results were not that positive and no further treatments are scheduled.

It has to be mentioned that this geothermal field is one of the only places where thermal fracturing has showed good results in terms of gain in production and injection capacity. At least 3 wells have been treated like that and results are good enough to continue to do so in future wells at a relatively low cost, Well H-40 is one of them (Flores et al., 2008).

TABLE 4: Results of matrix stimulation producing wells in the Tres Virgenes geothermal field

Well Name	Year	Type of damage	Mud losses m3	Placement technique	Production Capacity			Improvement	
					Original (t/h)	Pre-acid (t/h)	Post-acid (t/h)	Vs Original (%)	Vs Pre-acid (%)
LV-13	2002	Mud damage	5583	Coiled tubing	0	0	21	100%	100%
LV-11	2002	Mud damage	5119	Coiled tubing	12	12	35	192%	192%
LV-04	2004	Calcite scaling	-	Coiled tubing	32	9	42	31%	367%
LV-13	2004	Calcite scaling	-	Coiled tubing	21	14	28	33%	100%
LV-3	2006	Calcite scaling	-	Coiled tubing	25	0	0	No improvement	No improvement
LV-4A	2007	Mud damage	2700	Coiled tubing	0	0	20	100%	100%
LV-13D	2007	Mud damage	1326	Coiled tubing	0	0	20	100%	100%

TABLE 5: Results of matrix stimulation producing wells in the Cerro Prieto geothermal field

Well Name	Year	Type of damage	Mud losses m3	Placement technique	Production Capacity			Improvement	
					Original (t/h)	Pre-acid (t/h)	Post-acid (t/h)	Vs Original (%)	Vs Pre-acid (%)
307	2010	Mud damage	Not available data	Coiled tubing	55	12	32	No improvement	166%
208	2010	Mud damage	Not available data	Coiled tubing	70	0	42	No improvement	100%

TABLE 6: Results of matrix stimulation producing wells in the Los Humeros geothermal field

Well Name	Year	Type of damage	Mud losses m3	Place-ment technique	Production Capacity			Improvement	
					Original (t/h)	Pre-acid (t/h)	Post-acid (t/h)	Vs Original (%)	Vs Pre-acid (%)
H-01D*	2010	Silica and calcite scaling	-	Drilling pipe	42	6	45	7%	650%
H-33	2011	Silica and calcite scaling	-	Bull heading	8	8	0	No im-provement	No im-provement
H-41	2012	Low permeability	-	Bull heading	15	15	20	25%	25%

*Well with mechanical workover before the acid job

4. ECONOMIC ANALYSIS

In order to simplify the economic analysis in this paper, the prices for all acid stimulation jobs in Mexico has been calculated for 2011 prices, considering Mexican annual inflation indicators and a parity of 13 Mexican pesos to one American dollar was used. The estimated cost included all mobilizations, chemicals and additives, labor, equipment and personnel needed to perform the acid treatment. Results indicate that acid stimulation treatments performed using coiled tubing is less expensive than those done using a rig. Only two cases have been done using bull heading. Apparently these works are the less expensive, since it does not involve major equipment, but further investigation needs to be done to corroborate cost versus results in terms of production (Table 7).

TABLE 7: Comparative prices and results between placement techniques and equipment

Placement technique	**Average price 2011 US dollars**	**Average improvement %**
Using drilling pipe	1 195 339	249%
Using coiled tubing	866 181	158%
Using bull heading	628 147	25%
All techniques	1 002 305	176%

After getting the average cost in Mexico for an acid job, we decided to calculate what is the minimum improvement in production that is needed to get in order to pay off the expenditures and make the work a profitable one. To do that, CFE typically uses (COPAR, 2011) the following parameters for the economic evaluation of technical proposals:

- Discount rate > 12%;
- Median well life 5 years;
- Electricity cost 0.047 US$/ kWh;
- Operation & Maintenance cost 0.005 US$/kWh;
- Specific consumption in power units 9.3 t/h MW.

This economic analysis will assume that capital investments only include the cost of the stimulation treatment, without taking into account the cost of drilling the well, surface equipment, and power plant. This implies that the wells have produced sufficient steam to pay off these previous expenses, or that they are regarded as a sunk cost, which is not considered when evaluating future expenditure. The mean well lifetime is about 5 years due to casing and formation scaling, such as that in Las Tres Virgenes and Cerro Prieto. Excessive scaling reduces the production rate (or wellhead pressure) below the minimum values to allow connection to the power station (Flores et al., 2005). Different scenarios exist for other fields, such as Los Azufres or Los Humeros, where the median lifetime of the wells is above 15 years.

A production decline rate for this base case was set at 5% per year, even though lower declines have been observed in the real cases in the five years considered for the analysis. Economical runs where performed taking into consideration the investment and the operation and maintenance expenditures versus the incomes due to the sales of the equivalent produced energy (Figure 2). Results indicate that a minimal production of 15 t/h of steam is needed in order to pay for the investment in less than three years.

According to Flores et at (2005) using available technical and economical data in 2002, from the economic point of view, it was found that in liquid dominant reservoirs a minimum initial increase of ~8 ***t/h of steam*** is needed to make ***matrix acidizing*** a profitable prospect in Mexico, having a payback in less than three years. Similar economic analysis for the economic parameters in Iceland shows that a smaller gain in steam production is enough to pay for this type of stimulation treatment (Flores et al., 2005). Even though the electricity price for sales in that time was lower than in Mexico, the results

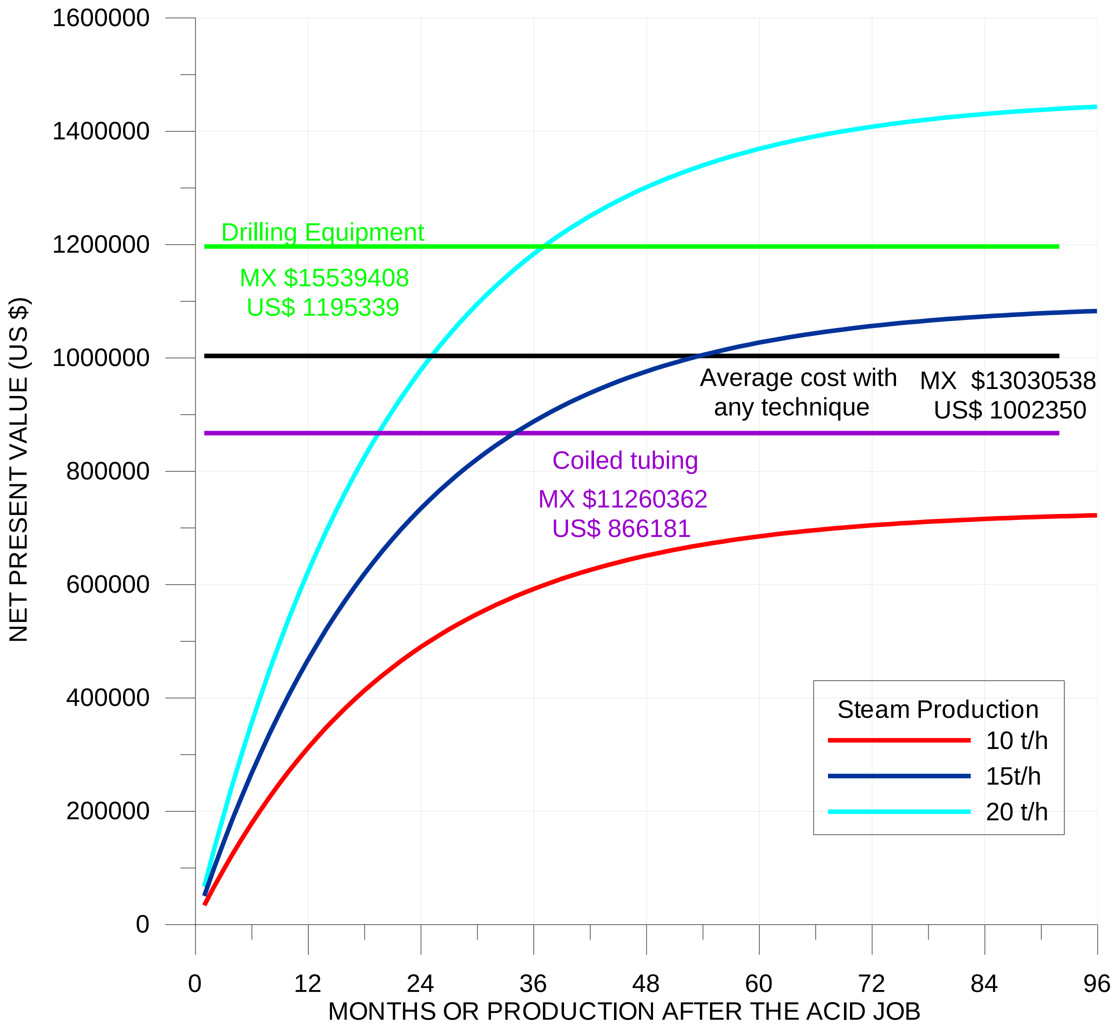

FIGURE 2: Investment and operation versus incomes to the sales of the produced energy

are basically due to lowest operation and stimulation treatment cost compare with those costs in Mexico at that time. Nowadays increments in production of at least 15t/h are needed to make it a successful inversion.

According to that paper also, thermal fracturing so far appears as a very inexpensive and effective treatment, according to the economic analysis and to the coupled flow and geomechanical modelling, however it is still subject of additional research to understand the mechanism that control the permeability improvement, but there is no a studies about the economical results of such treatments in Mexico. That should be done in the near future.

5. CONCLUSIONS

Matrix acidizing to clean up existing fractures was found to be fully applicable to geothermal environments, but specific technologies suitable for high temperatures and long intervals, such as a reduction in reaction rate and diversion, needs to be considered to maximise the efficiency of the treatment.

Very limited successful cases were found in fracture and high temperature formations when stimulating the formation with a ***Hydraulic Fracturing*** treatment. This technology has to be tested at geothermal reservoir conditions so that confidence can be gained if its application is essential for the delivery of economic development wells. Specific technical issues such as thermal degradation of fracturing fluids and excessive leak-off leading to an early screen-out, need to be considered.

Thermal fracturing was also found to be fully applicable to geothermal environments. This technique shows great promise as a cost effective treatment for geothermal wells. This is based on the reported field results and the significant changes in effective permeability calculated during preliminary modelling work. Economic analysis showed it to be highly cost effective. The preliminary results indicated that the degree of permeability enhancement is a function of injection time, fracture pattern and distance away from wellbore.

From the economic point of view and taking into consideration economical information in 2011, it was found that in Mexican geothermal reservoirs a minimum initial increase of ~15 ***t/h of steam*** is needed to make ***matrix acidizing*** a profitable prospect in Mexico, having a payback in less than three years.

In term of results, 23 out of 26 acid treatments were successful in the geothermal fields in Mexico. The average percentage of improvement ranges from 13 – 540%, with an average of about 176%.

At present, all acid treatments being conducted by the CFE in Mexico use the mud acid (HC1-HF) system to treat formation damage caused by drilling mud and mineral (silica) deposits. The acid treatments conducted have generally used a pre-flush of 10%HC1 and a main flush of 10% HC1-5% HF.

In terms of drilling savings, these acid jobs saved the equivalent of the drilling cost of 18 new production wells using an average production of 30 t/h of steam and two new injection wells over 11 years.

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