The Larderello – Travale and Amiata Geothermal fields: case histories of engineered geothermal systems since early 90's

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ABSTRACT

The development of geothermal fields in Tuscany is related to the exploitation of deep reservoirs in metamorphic and granitic rocks. The permeability of fractured zones can be reduced during the well completion by occlusion of fractures with accumulated debris or drilling mud, or during the well production life by salts deposition.

Since 1980, in order to increase the productivity of individual wells after drilling and to preserve it during their production life, some stimulation techniques have been developed and are currently being implemented. The aim of these techniques is to improve the permeability of fractured zones and to reduce or eliminate the formation damage (skin factor) by means of acid stimulation (HCl and HF).

With the experience gained during the operation and maintenance of the wells, different causes of well damage (formation or wellbore) have been identified and different techniques aimed to the recovery of the original productivity have been studied and implemented; some of these are also based on the injection of water.

This paper discusses the criteria used to identify the suitable wells and the different types of well stimulations, moreover some history cases are shown.

1. INTRODUCTION

The natural thermal manifestations of the Larderello region (known also as the "boraciferous region"), have been well know since Roman times. Remains of a Roman thermal bath can still be seen near Monterotondo. Products of the thermal manifestations (sulfur alum, boric acid, vitriol, coloured clays, etc.) were used in the Middle ages in pharmacology and pottery.

The modern history of Larderello is traced from the beginning of the nineteenth century when Count François De Larderel left France and began the industrial exploitation of the boric acid discovered at the end of the eighteenth century in the area of natural steam vents. There are no precise data on the nature of the fluid in the reservoir and at the surface at that time.

It is, however, very likely that in some areas of the field, the natural fluid emerging at the surface was superheated steam. (Minissale,1991).

In the 1904 Prince Piero Ginori Conti, who had inherited from De Larderel family the management of the boric acid industry, performed the first experiment worldwide of electric energy generation by means of geothermal power. A motor fed by geothermal steam coupled to a dynamo was put into operation lighting five bulbs.

The year after , based on the same principle, a motor coupled to a 20kW dynamo was put into operation, providing energy to the entire boric acid factory. Finally, in the 1913 the first geothermal power plant (250kW) was put into operation supplying energy to the whole Larderello chemical plants and also to some villages of the boraciferous region. (Ciardi e Cataldi, 2005).

The technological innovation made by Prince Ginori Conti represented the starting point for the geothermal power industry all over the world. Over the years plants, drilling and fluid treatment technologies have been implemented allowing, together with a clever reservoir management, the installation of 875 MW_{gross} capacity in the geothermal fields present in the Tuscan region.

The Larderello – Travale - Radicondoli geothermal system, located in the western Tuscany, represents one of the few vapor dominated reservoir presently known to exist together with The Geysers, Kamojang and Darjat (Grant and Bixley, 2011).

The field can be subdivided into three reservoirs hosting overheated steam in different formation rocks but being in vaporstatic equilibrium. The first reservoir is hosted by Mesozoic limestone and anhydrite at depth between 500m and 1500m, the second one of metamorphic rocks at depths between 1500m and 4000m (Bertini et al., 2006), while the third one, found and exploited only in the Travale-Radicondoli portion, is made of granitic rock and generally deeper than 3000m.

Nowadays the steam exploited from this system feeds 755 MW_{gross} out of a total installed capacity of 795MW_{gross}.

The Mount Amiata geothermal field, located in southern Tuscany about 70 km SE of Larderello, is a liquid dominated system constituted by two reservoirs in hydrostatic equilibrium but completely separated by at least 800-1000m thick impermeable rocks. The shallow productive horizon is made of Mesozoic limestone and anhydrite while the deep reservoir is hosted by metamorphic rocks (Bertini et al., 1995).

The saturated steam extracted feeds all the 80MW_{gross} of installed capacity.

2. WELL DIAGNOSTIC AND STIMULATION TECHNIQUES

The term Engineered Geothermal Systems (EGS) is used to refer to a range of experimental projects that involve modifying rock permeability in order to create a geothermal reservoir or to enhance an existing one (Grant and Bixley, 2011).

Geothermal wells are put in production at a quasi constant flowing pressure determined by the pipelines and the power plant inlet pressure; the production rate is generally not constant and may decrease due to the natural reservoir decline.

Sometimes an anomalous sharp production decline is experienced, this is due to an increase of the resistance between the reservoir and the wellbore which can have different causes, including wellbore scaling, openhole restrictions, casing damages.

In some other cases an increase of the resistance may be due to an increased skin effect. Pressure transmission does not take place uniformly throughout the reservoir, since it is affected by local heterogeneities. For the most part, these do not affect the pressure change within the well, except those reservoir heterogeneities which are in the immediate vicinity of the wellbore. In particular, there is often a zone surrounding the well which is invaded by mud filtrate or cement during the drilling or completion of the well. This zone may have a lower permeability than the reservoir at large, and thereby acts as a skin around the wellbore, causing higher pressure drop.

Quantitatively, the skin can be defined as a constant which relates the pressure drop in the surroundings of the wellbore to the flow rate and to the transmissivity factor kh (Matthews and Russell, 1967):

$$\Delta P_{skin} = s\left(\frac{q\mu}{2\pi hk}\right) \qquad [1]$$

Introducing this in the radial flow equation for an infinite acting reservoir:

$$P_w(t) = P_i + \frac{q\mu}{4\pi hk}\left[\ln\left(\frac{\gamma\Phi\mu C_t r_w^2}{4kt}\right) - 2s\right] \qquad [2]$$

Where P_w is the flowing pressure at a certain time and P_i is the infinite reservoir pressure.

From [2] it is possible to understand how the skin affects the flowing pressure by the amount indicated by [1].

The skin can be described also in terms of effective wellbore radius (r_{weff}), this is the smaller radius that the well appears to have due to the reduction in flow caused by the skin effect:

$$r_{weff} = r_w e^{-s} \qquad [3]$$

The pressure drop across the skin (ΔPs) is the difference between the actual pressure in the well when it is flowing, and the pressure that would have been if the well were undamaged.

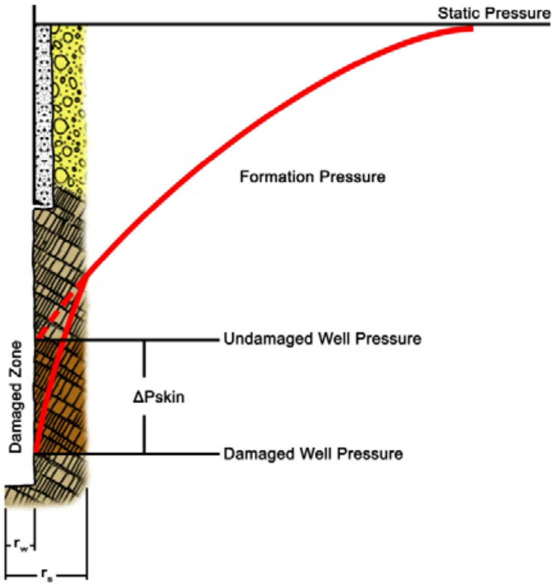

Figure 1: Comparison between pressure drainage cone for a damaged and a undamaged well

If the skin zone permeability k_s is higher than that of the reservoir (as can happen due to stimulation) then the skin effect is negative and the effective wellbore radius will be greater than the actual one.

In a geothermal well a production decline may take place even if an acid stimulation was performed immediately after drilling.

The first useful tool in well diagnostic is the production history. By means of the analysis of those data it is possible to decide if the decline is small and constant or abrupt. Moreover it is possible to make a rough calculation of the reservoir pressure and its decline, in order to understand whether or not it is consistent with the entire field decline.

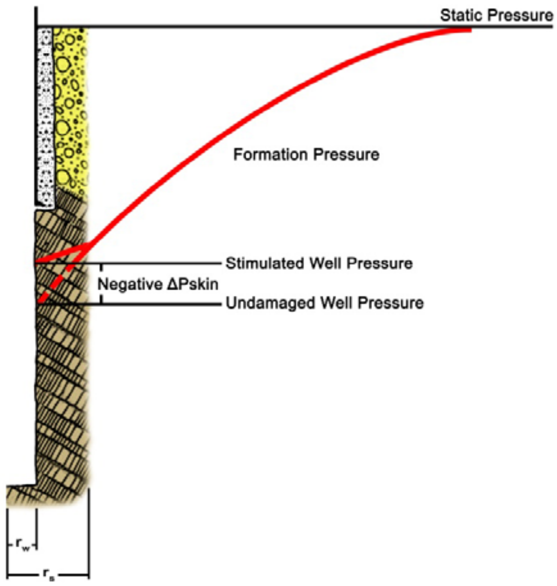

Figure 2: Comparison between pressure drainage cone for a undamaged and a stimulated well

If the production loss is considered to be abnormal with respect to the general reservoir pressure decline, a complete well diagnosis is advisable:

- Measure pressure, temperature and flow rate at the well head.
- Shut in the well and record the pressure build-up.
- Wellbore caliper inspection.

Performing the build-up test has the main advantage of an easy to achieve constant flow rate condition, since the flow rate is zero; with this pressure transient test it is possible to analyze different behaviors at different times; i.e. storage in the early time, infinite acting aquifer in the intermediate time and closed boundary/constant pressure in the late time.

The analysis of this time responses, besides the skin factor, lead to the computation of fundamental diagnostic parameters such as: the storage volume, that compared with the well volume may indicate an obstruction into the well or a collapse; transmissivity factor (kh) , that compared with typical values of the field or previous values on the same well may be an indication of altered rock properties; the reservoir pressure, that can match the typical value of the field validating the test or not. Performing a practicability log one can definitely confirm or deny obstructions in the cased zone or collapse in the openhole.

Only after the study of the entire well production history and the execution of those tests it is possible to define the main cause and so the most suitable strategy in order to gain a production level similar to the original one.

As it will be shown in some case histories, a well can have a storage volume similar or lower than the wellbore volume, indicating an obstruction in the wellbore. In this case different options are available depending on the type of the obstruction, from a flush in case of salts deposition to a work over in case of wellbore collapse. In other cases the buildup test analysis may show a positive skin; in this case an acid stimulation could be affective even if the storage volume results greater than the wellbore volume.

Normally HCl or mixtures of HCl and HF are used for stimulation treatments, with different ratios according to the geothermal reservoir rock nature. When the acidification is performed on the Tuscan shallow reservoir, mainly constituted by limestone and anhydrite, a treatment with HCl is adequate. In case of deeper reservoir, hosted in metamorphic or granitic rocks (quartz and phyllosilicates), a mixture HCl:HF is needed.

Acidifications are made following a well defined procedure:

- Measure well head pressure, temperature and flow rate.
- Shut – in and record the pressure build up.
- When the wellhead pressure reaches a steady value, an injection test with increasing flow rate is performed in order to: achieve a soft cooling of the wellbore and avoid thermal shocks to the casing, test the injection capability of the well. This phase is really important for the success of the whole procedure, because it can give further indication about obstructions or collapses, and in terms of safety for the operators who will later perform the acid injection.
- Once the injection capacity of the well is tested, the acid treatment can be performed as follows:
    - Preflush of clean water for a soft cooling of the well in order to reduce the temperature during the treatment and so the amount of inhibitor needed to avoid any reaction between the acid and the casing;
    - Mainflush of HCl or a mixture of HCl:HF to dissolve carbonates and silicate minerals and drilling mud;
    - Postflush of clean water to displace unreacted acids and reaction products away from the wellbore;
- Shut – in and record the build - up.
- Once the wellhead pressure recovers its typical value, it is possible to open the well for a production test measuring: well head

pressure and temperature, flow rate, gas/steam ratio, chloride-fluoride content.

- Only when the chloride-fluoride concentration is acceptable and the typical thermodynamic conditions at wellhead are reached again, it is possible to connect the well to the gathering system.

For the wells characterized by an obstruction in the wellbore due to salt depositions, depending on the type of salt, it can be sufficient to clean the well by means of a clean water flush or a mixture of NaOH and water. A flush with NaOH at high pH values is exclusively performed when antimony sulfide depositions with low silica matrix are found. In this case also HCl would be effective but, since the treatment needs to be performed for several days (low rate of penetration) at low flow rates, it is preferable to use sodium hydroxide which is easier to handle for high operation times and does not require any inhibitor.

The acid injection flow rate is a very important parameter to set, because it influences how and where the acid reacts. As a general consideration is considered that a high flow rate (more specifically high flow rate per meter of wellbore to treat) increases the radial length of the acidizing and then the extension of the zone where the permeability improves. For this reason the solution is usually fed at the maximum flow rate possible, except when the wells have more than one important productive fracture with different elevations. In this case it is hard to treat all of them simultaneously and a selective treatment is possible depending on the injected flow rate.

3. CASE STUDY

Below are given the behaviors of three different wells, two producers and an injector. The studies carried out on the operation histories led to different diagnostic assessments and so to different recovery and improvement strategies.

WELL A

The first case is a well producing superheated steam, its main characteristics are reported in the table below.

kh [Dy*m]	10
Well depth (TD) [m]	4012
Fractures depth [m]	2445 3050 3200 3700 3900
Injectivity [m^3/h/bar]	8.5
Well volume [m^3]	155
Reservoir rock	Metamorphic

Table 1: Main characteristics of the Well A.

The well A was acidized at the end of drilling in order to clean all the fractures from any cement or drilling mud. As previously explained, since the reservoir was hosted in metamorphic rock, it was decided to use a mixture HCl:HF.

From the production history reported in figure 3 it is possible to understand the importance of the production monitoring as a tool for diagnostics. Initially producing around 65 t/h of steam it experienced a decline of about 25 t/h in almost 2 yeas, with the flowing pressure always being constant.

Considering the equation that gives the production curve for a well in a steam dominated reservoir:

$$P_{res}^2 - P_{fl}^2 = \alpha G + \beta G^2 \qquad [4]$$

where P_{res} is the reservoir pressure, P_{fl} is the flowing pressure at the wellhead, G is the steam flow rate, α represents the laminar flow resistance coefficient in the formation and β the turbulent flow resistance coefficient in the wellbore (calculated according to the geometry of the wellbore and considered to be constant in time). This states that for a given pressure drop between the reservoir and the wellhead, the steam flow rate is given by laminar and turbulent resistances.

Using the initial reservoir pressure and production data of the first year, considered to be stabilized, starting from [4] it is possible to make a first calculation of α. Using this value of α and subsequent production data, a reservoir pressure can be calculated. The reliability of these values need to be verified then by means of pressure transient tests.

Observing the computed reservoir pressure and its trend, reported on the production history in figure 3, some considerations can be made.

The grey zone underlines the time window in which a sudden flow rate decline was experienced. In the same period also the computed reservoir pressure had an inexplicable drop (see the difference before and after the beginning of 2009).

Considering this, a schedule of periodic controls consisting of build-up pressure tests, followed by an inspection log, were performed. In this way it was possible to calculate the skin factor, formation transmissivity, storage volume and the reservoir pressure, comparing it with the reservoir pressure calculated with the above mentioned method.

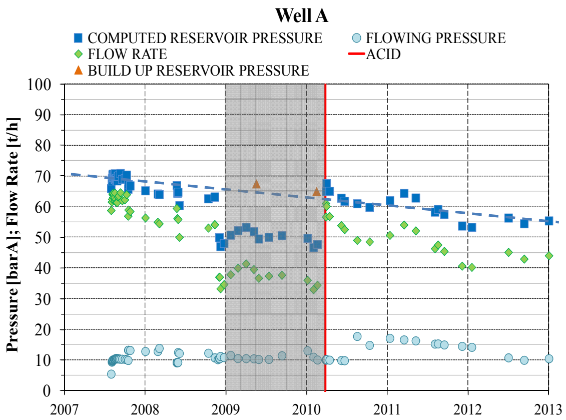

Figure 3: Well A production history

Data recorded by pressure build-up tests are employed on a log-log plot of the pressure difference ΔP and its derivative ΔP'. This is the most effective procedure for analyzing and understanding the entire recorded transient well test data.

Early time data give information on the reservoir around the wellbore, such as storage and skin, subsequently an infinite-acting radial flow can be inferred (Ahmed and McKinney, 2005).

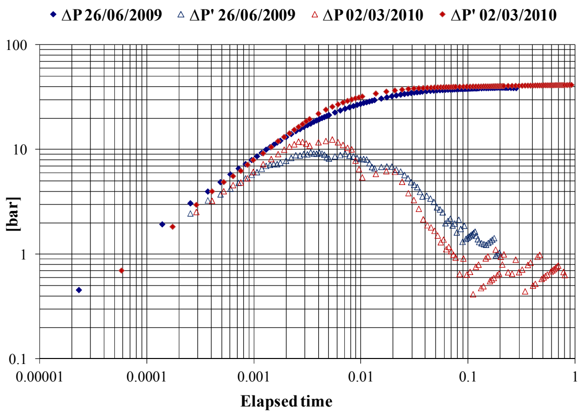

Figure 4: Log-log plot for the build-up tests performed on the well A, derivatives are represented by triangles

The figure 4 reports the log-log plot for both the build-up tests performed on well A. As it is possible to observe the wellbore storage produces a 45° straight line on the log-log plot while the transition from pure wellbore storage to infinite acting behavior gives a "hump" in the derivative with a maximum that characterizes wellbore damage (positive skin factor s).

All the periods mentioned above are well defined: wellbore storage at early times, an hump due to the skin effect, transition and infinite acting radial flow.

The sequence of the tests and main results are reported in the table below.

Date [mm/yyyy]	Type of test	kh [Dy*m]	skin	Pres [barA]	Notes
06/2007	End of drilling operations and acid stimulation				
06/2009	Build-Up	11.4	+14.3	67.5	$V_{st} \approx V_{wb}$
07/2009	Inspection log				
03/2010	Build-Up	14	+19	65	$V_{st} \approx V_{wb}$
04/2010	Acid stimulation				

Table 2: Sequence of tests and treatments performed on the Well A and main results.

The analysis carried out on the first build – up confirmed a positive skin and a storage volume close to the one of the wellbore. Moreover the reservoir pressure computed by means of the build-up analysis is close to the one computed with production data (see dashed line in figure 3).

On the other hand, during the inspection log, the well was found completely free.

Despite the results obtained with the tests performed in 2009, it was decided to postpone the acid stimulation since the production was still acceptable. Subsequently a continuous depletion in the flow rate and a new increase of the skin was observed, as denoted by the production history and by the results of the second pressure build-up (03/2010).

Considering this, the risk associated to a stimulation job, such as wellbore damage during the flushes, was considered proportional to the expected gain.

The treatment was performed with an HCl:HF mixture, flushing the well with clean water before and after the acid.

The vertical red line in the figure 3 marks the acid treatment. It is possible to observe how, after the stimulation, the well regained an acceptable value of production (+15t/h stabilized) and a consistent value of reservoir pressure that matches the ones calculated with the build-up tests.

Recalling [4] it is also possible to make a rough calculation of the flow resistance in the surroundings of the wellbore also before and after the treatment. Main results are reported in the table below.

The laminar flow resistance coefficient is strictly related to the permeability of the porous media, assumed to be constant, and to the skin.

Reducing the skin effect, the treatment almost halved the coefficient α restoring a value close to the one calculated at the beginning of well production.

Condition	Initial	Before acid	After acid
P_{res} [barA]	70	65	65
P_{fl} [barA]	10	10	10
β [bar^2/(t/h)^2]	0.45	0.45	0.45
G [t/h]	64	34	56
α [bar^2/(t/h)]	**47**	**106**	**48.5**

Table 3: Laminar flow resistance coefficient calculation over the time.

Finally, it is possible to state that the acid treatment was successful and allowed to gain a significant production rate. The procedure was effective and avoided any damage in the casing or in the open hole.

WELL B

The second case study envisages another steam producing well. Its main characteristics are reported in the table below.

kh [Dy*m]	25
Well depth (TD) [m]	2115
Fractures depth [m]	2110
Injectivity [m^3/h/bar]	12
Well volume [m^3]	169
Reservoir rock	Metamorphic

Table 4: Main characteristics of the Well B.

At the end of drilling the well B was put in operation without any acid treatment.

In figure 5 is reported the well production history. It is possible to observe how the well, starting from a flow rate of about 40 t/h, immediately showed sudden decline of 10 t/h with the flowing pressure being constant. Subsequently, between 2003 and 2010, a new abrupt decline was experienced with a decrease of further 15 t/h, even with a lower flowing pressure.

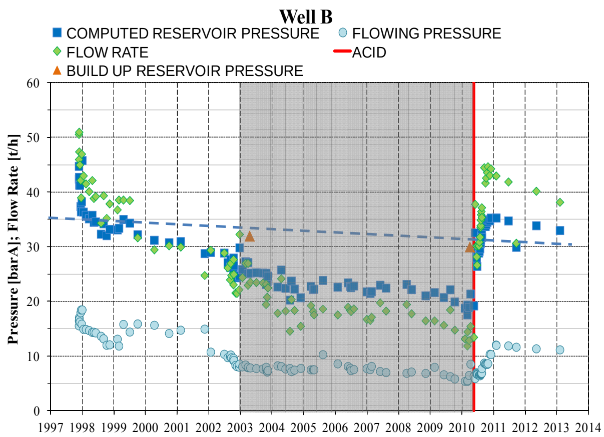

Figure 5: Well B production history

As the grey zone shows, in this period also an inconsistent decline in the reservoir pressure was computed.

Considering this, two build up tests were performed in that period. Main results are reported in the table below.

Date [mm/yyyy]	Type of test	kh [Dy*m]	skin	Pres [barA]	Notes
03/1993	End of drilling operations				
04/2003	Build-Up	25	+3.5	31	$V_{st}>>V_{wb}$
05/2010	Build-Up	20	+8.5	30	$V_{st}>V_{wb}$
05/2010	Acid stimulation				

Table 5: Sequence of tests and treatments performed on the Well B and main results.

The first build up, performed in 2003, showed a positive skin. Nevertheless taking into account the flow rate, still acceptable, it was decided continue monitoring the well and postpone any treatment.

At the beginning of 2010, considering a new decrease in the flow rate, it was decided to acidize the well. Before the treatment, during the shut in of the well, a new pressure build up was recorded. The analysis carried out showed a further increase in the skin (+8.5) and reservoir pressure significantly different if compared with the one computed by production data.

The presence of a skin effect and its increase during the years can be appreciated in the figure 6, where the pressure difference ΔP and its derivative ΔP’ are reported on a log-log plot.

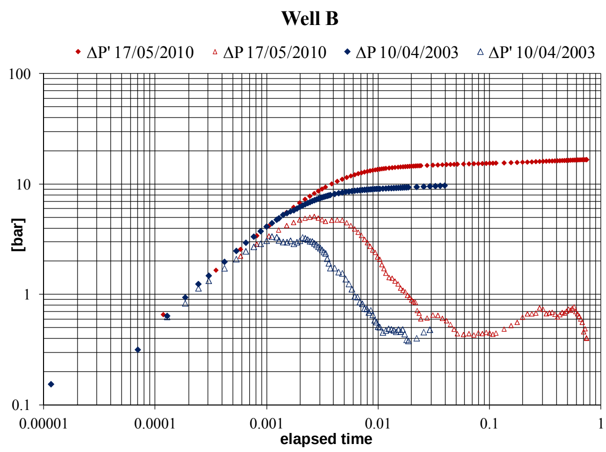

Figure 6: Log-log plot for the build-up tests performed on the well B, derivatives are represented by triangles

Looking at the height of the hump, even more than in the previous case (well A), it is possible to see how the skin increased over the years.

Since the reservoir is hosted in metamorphic rock, the treatment was performed with a mixture of HCl and HF.

As it can be observed in the production history, after the acid treatment the well gained almost 25 t/h and with an higher flowing pressure. Besides, the computed reservoir pressure recovered a value similar to the one calculated by means of the build - up tests and consistent with the initial decline trend.

A calculation of the laminar flow resistances α can be done also in this case.

Condition	Initial	Before acid		After acid
		2003	2010	
P_{res} [barA]	32	31	30	29
P_{fl} [barA]	15	8.5	7	11
β [bar^2/(t/h)^2]	0.06	0.06	0.06	0.06
G [t/h]	37	24	13.5	35
α [bar^2/(t/h)]	**19.4**	**35.6**	**62.2**	**18.5**

Table 6: Laminar flow resistance coefficient calculation over the time (changes in flowing pressure are due to different inlet conditions at the power plant over time).

Also for the well B a continuous increase of the laminar flow resistances coefficient can be observed. Moreover it is clear how the acid treatment enhanced the connection with the reservoir in the surroundings of the wellbore, restoring a value of α close to the initial one.

WELL C

The third case study is based on an injection well needed in the management of a liquid dominated reservoir. This well is fed by the liquid separated on the production pads.

The main characteristics of the well are reported in the following table.

kh [Dy*m]	4
Well depth (TD) [m]	1024
Fracture depth [m]	525
Injectivity [m^3/h/bar]	5
Well volume [m^3]	42
Reservoir rock	Limestone and anhydrite

Table 7: Main characteristics of the Well C.

Being known the scaling potential of the injected fluid a monitoring plan, made of injection and inspection logs, was scheduled on this well. The aim was to keep the wellbore conditions and the injectivity always under control.

Date [mm/yyyy]	Type of test	I [m^3/h/bar]	Maximum depth [m]
01/1992	Inj log	3.5	/
04/2001	Inj log	0.5	/
10/2004	Acid stimulation		
10/2004	Inj log	2	/
08/2006	Inspection	/	85
09/2007	Acid stimulation		
08/2008	Inj log	0.5	/
09/2008	Inspection	/	138
10/2008	NaOH stimulation		
10/2008	Inspection	/	797
10/2008	Inj log	5	/
12/2011	Caliper log	/	280
12/2011	NaOH stimulation		
12/2011	Caliper log		465 (shoe)

Table 8: Sequence of tests and treatments performed on the Well B and main results.

At the beginning, acid treatments were performed assuming an increase of the formation resistance. After an inspection log depositions on the casing were sampled and found to be antimony sulfide (Sb_2S_3) with low silica matrix. Considering this piece of information, water and NaOH was injected at very low flow rates for several days.

The difference in terms of performances are highlighted in the table above: acid treatments are less effective in terms of global injectivity, not higher than 2 m^3/h/bar, and are required more often, once every two years. The lapse of time between one water - NaOH treatment and another is higher than three years, while the injectivity reached the highest value ever (5 m^3/h/bar).

As described in the chapter 2, this is mainly due to the low rate of penetration during the flush. An acid treatment is more effective on the formation damages than in the casing scale. Sodium hydroxide is easier to handle, does not require an inhibitor and thus it can be performed for several days effectively acting on the salts depositions in the wellbore.

The effectiveness of the treatment has been demonstrated also by means of caliper logs before and after the treatment (figures 7 and 8).

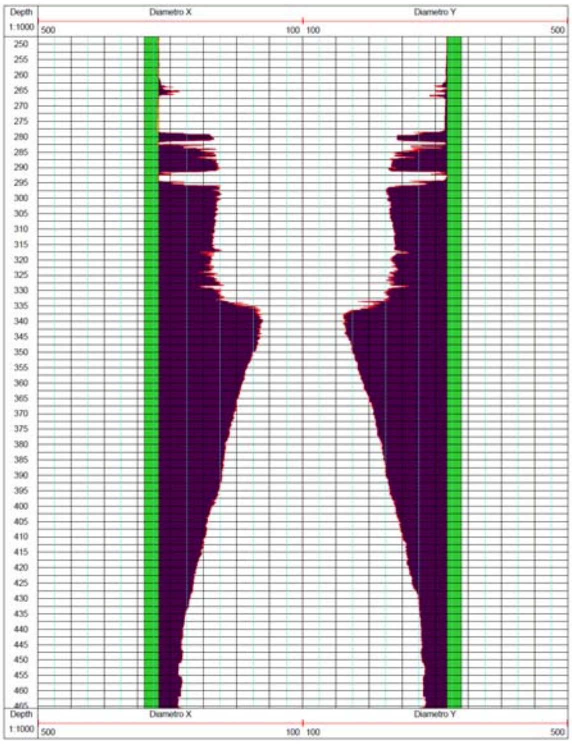

Figure 7: Caliper log performed on the Well C before Water+NaOH treatment

In figure 7 is reported the caliper log executed before the NaOH flush. The normal diameter is colored in green while the obstruction caused by Sb_2S_3 is clearly visible in purple.

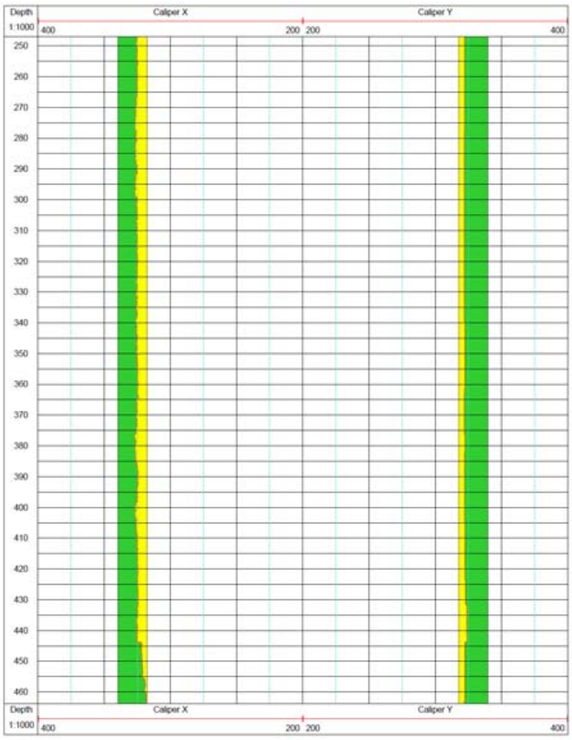

Figure 8: Caliper log performed on the Well C after Water+NaOH treatment

Figure 8 shows the same part of the wellbore after the treatment. No scale was recorded, while there is a zone with a diameter higher than the nominal one (yellow colored zone), probably due to casing wear.

4. CONCLUSIONS

The study of the production or injection history of a well is of primary importance in the diagnostics of a well. In fact, observing the behavior of a well it is possible to design possible additional tests to improve production.

In most cases, a wise use of tools such as operational history, transient pressure tests, injection logs and caliper logs allows implementing the most cost effective actions. The most striking example is represented by the performance of an acid treatments instead of a drilling work over.

As already mentioned, diagnostic tests and improvement actions must be performed with caution. Analyzing the performance of a well, such as the production decline, also the possibility of complete loss of production must be considered. Judging the effectiveness of tests and treatments a comparison between the anticipated gain and the potential risk is needed.

Only in this way Enel Green Power experience in geothermal fields management, gained over decades, allowed obtaining positive results in a continuously increasing number of cases.

This point is highlighted in table 9, where it is possible to observe how the effectiveness of the treatments improved over time.

Time lapse	Positive outcome
1979-1989	33.3%
1990-1999	39.3%
2000-2009	51.2%
2010-2013	80.0%

Table 9: Improvement of the treatments effectiveness on the production wells over time

These results are referred to all the treatments aimed to production recovery.

Generally speaking, more than 240 treatments were conducted since the end of 1980’s until now. More than 100 treatments were made at the end of the drilling activities mainly aimed to clean the well from drilling mud or debris and to increase formation productivity. In this cases is difficult to evaluate the effectiveness of those treatments, since the initial state is often unknown.

In almost other 100 cases treatments were made during the well operation period with the aim to improve the production rate or restore it. In 104 cases catalogued and examined, 54 had a positive result with a significant increase in the production flow rate, 43 had a negative result with a negligible increase and in 7 cases information are not enough to define a clear outcome.

At this stage, the following conclusions can be drawn: in the 52% of the cases the treatments resulted to be effective with an average steam flow rate increase of 14 t/h.

Also treatments performed on injection wells had a global positive outcome, with injection capacity enhanced in 24 cases out of 32.

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