Well intervention techniques

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Abstract

The Philippine National Oil Company – Energy Development Corporation (PNOC-EDC) has effectively employed several well intervention techniques to address the requirements of sustaining long-term operation of its geothermal production fields. This paper reviews the different intervention techniques and their application to the several field management problems encountered during exploitation. Experiences obtained from these intervention procedures have shown that the chance of success is generally increased with a correct and appropriate engineering approach to any well problem.

1 Introduction

Drilling of maintenance and replacement wells is the common option used to maintain or improve the capacity of the field. Well workover options are also available depending on the problem and circumstances in the field. The main objective of such options is to improve and optimize the performance of the wells and the reservoir in general. Most of these well intervention techniques PNOC-EDC (Philippine National Oil Company – Energy Development Corporation) has implemented, consist of: a) blockage (scales) drillout; b) casing perforation; c) casing repair; d) zone plugging; e) acid treatment; and f) hydraulic fracturing (Sarmiento, 2000). These workover operations involve the use of a drilling rig or coiled tubing unit to carry out the rehabilitation of the well.

2 Scales drillout

Mineral deposition has been occurring in some of the production and injection wells in most of the production fields operated by PNOC-EDC. Figure 1 shows the PNOC-EDC project locations in the country, with a geothermal installed capacity to date of 1,154 MWe. Anhydrite blockages occur in production wells where there is mixing of calcium-rich fluids with the sulfate-rich fluids from the different feedzones during production. In some cases, calcite scaling occurs in the production wells with high CO_2 content in the discharge fluid. Silica scaling is normally encountered in the injection wells when the reject brine, supersaturated with silica, is injected for disposal. The occurrence of these problems reduces the productivity and injectivity of the wells, and so require corrective action.

 PNOC-EDC usually clears the wells that encounter mineral deposition by mechanical drill-out to restore their capacity. This operation produces positive results as shown in Figure 2 below. Injection well 2R4D[1] had an initial capacity of around 85 kg/s at start up operation but steadily declined to around 40 kg/s over the years due to silica deposition inside the wellbore. A workover (scales drillout) operation conducted in the well in 1990 restored its injection capacity but was sustained for only a short duration, indicating that scaling had

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[1] D stands for deviated

already occurred in the immediate vicinity of the wellbore. The injection capacity declined rapidly after about a month from workover. As the scales drillout in the well only removed the obstruction inside the wellbore, an acid treatment was also conducted to dissolve the silica deposits in the formation wherein significant improvement was attained after the treatment.

Figure 1: PNOC-EDC geothermal project locations (Sarmiento, 2000).

3   Casing perforation

This well intervention technique has been employed by PNOC-EDC to production wells mainly to access the cased off production horizons that still have commercial temperatures and pressures. The majority of these horizons are shallow two-phase zones that were initially cased off in the development stage of the production field to minimize anticipated drawdown. Recent developments in the utilization of the field, however, prompted PNOC-EDC to explore the possibility of tapping these zones for additional production. The cased off permeable zones are evaluated based on the correlation of drilling, geological and petrological data. The perforated zones are also usually enhanced by acid treatment.
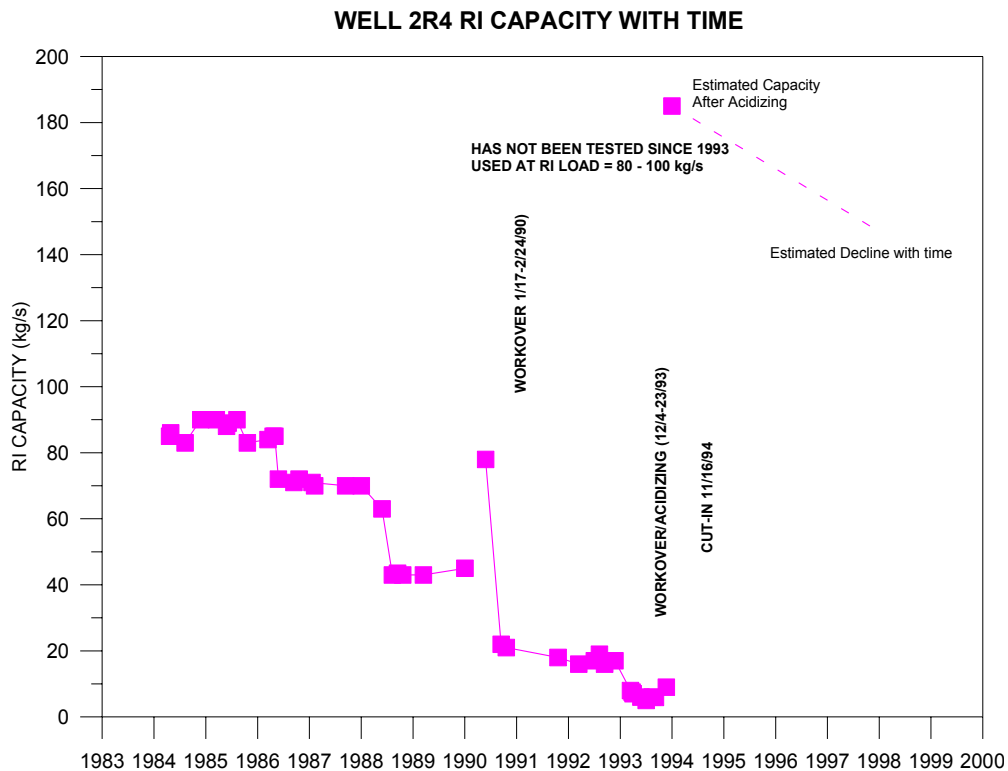
WELL 2R4 RI CAPACITY WITH TIME

Figure 2: Well 2R4 injection capacity with time (Buñing et al., 1995).

3.1 SK-2D casing perforation

The natural steam cap and two-phase zone in the Mindanao 1 Geothermal Production Field (M1GPF) was discovered upon production testing of one of the wells, and after most of the wells directed to that sector of the field had already been completed, with these productive zones cased off. The possibility of increased production capacity and reduced injection load for the first 52 MWe power plant by tapping these shallow two-phase and steam zones was then evaluated. SK-2D is one of those wells which was believed to have intersected the steam cap in M1GPF and for which intersection was cased off and cemented (Buñing et al., 1997; Malate et al., 2000).

Drilling records, and temperature and pressure data from completion and check-up surveys were used as initial information in designing the casing perforation job. Preliminary targets were then correlated with geological structures in the area to minimize the probability of targeting localized structures. Deep-penetrating (DP) perforating charges capable of 24 inches penetration into cement (API RP-43) have been used to ensure communication around the 12 1/4" nominal ID borehole (cased with 9 5/8" K-55 steel casing). Entry hole diameter of each charge measured about 0.45 inch, equivalent to about 1.9 square inches of perforated cross-sectional area per foot interval, shot with 12 shots/foot 6" OD expendable casing guns. This falls much below the flow cross-sectional area available from standard surface-slotted production liners (over 10 square inches per foot interval), but expectation of steam production in contrast to liquid water proved to be enough justification to proceed with the design.

Perforation was conducted extremely overbalanced (with the help of the temporary plug), by keeping a 1,000 psig pumping WHP at the time of detonation. With successful communication with a permeable horizon, the wellhead pressure would decline and not be able to recover even at continued pumping. With limited permeability in the accessed zone, the wellhead pressure was expected to initially drop but gradually recover with continued pumping. With failure to connect with a permeable zone, the pressure would drop initially,

and immediately rebound to original level with continued pumping. This enabled immediate determination of communication between wellbore and formation after fires had been shot.

While initial perforation targets were influenced by the observation of drilling losses and temperature "kicks", refinement was achieved through a combination of CBL/VDL logs and electronic temperature and pressure logs just before the perforation job commenced (Figure 3). It has to be emphasized here that PNOC-EDC uses standard mechanical clock-driven temperature and pressure gauges in its regular downhole surveys.

The CBL/VDL logs were done to verify the cement condition behind casing vis-à-vis the observed temperature kicks. The electronic temperature and pressure logs were conducted 4 hours after the well was quenched for 2 days. The new temperature profile then displayed intervals of relatively faster heating, which the authors relate with closeness to or communication with a convective zone. As Figure 3 illustrates, two long bands of target (690-870 m, and 910-1120 m) have been reduced to six short and separated intervals located as close as possible to total loss circulation (TLC) zones and to zones of rapid temperature build-up in the new logs.
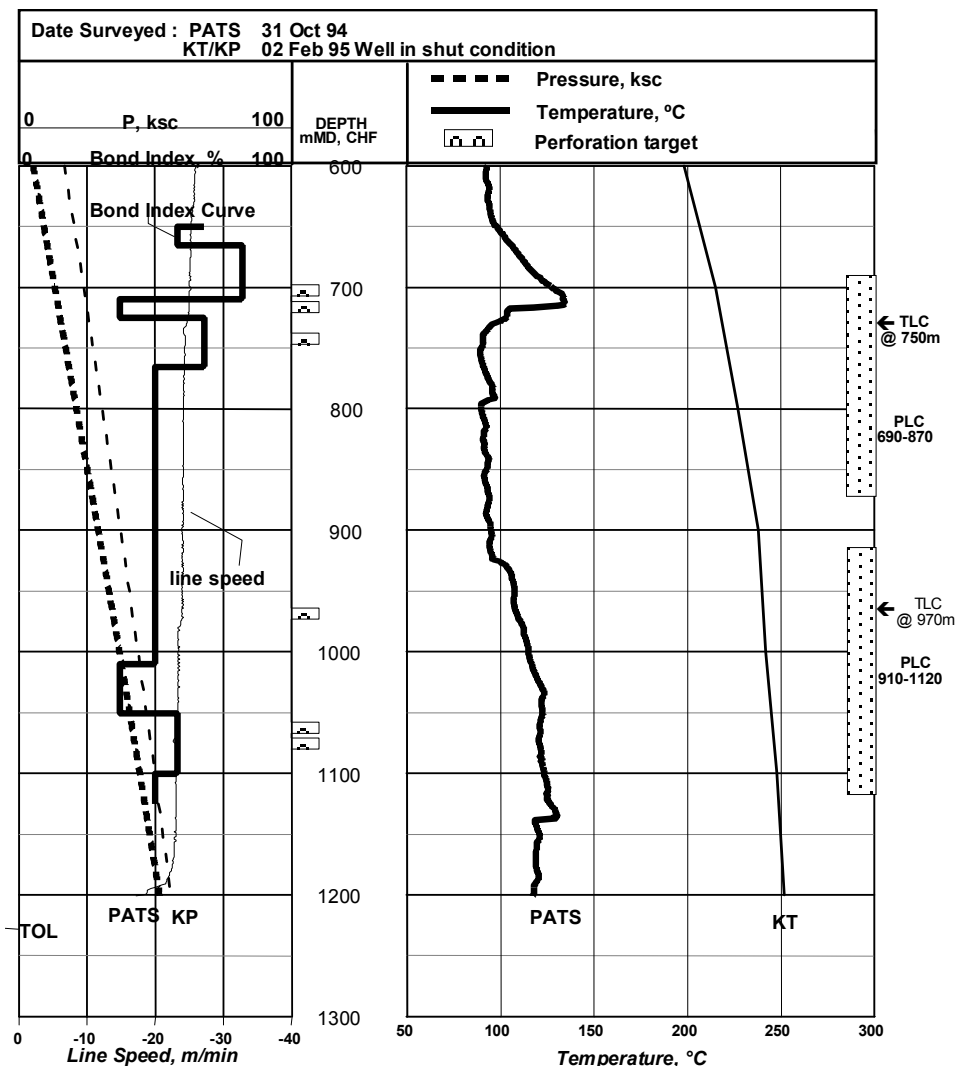

Figure 3: CBL, electronic temperature and pressure logs and KT/KP profiles used to refine perforation targets in SK-2D (Malate et al., 2000).

The perforated zones were also treated with a mixture of 10%HCl-5%HF mainflush solution to dissolve the mud and cement sheath near the wellbore. The mainflush acid volume used was equivalent to 75 gallons per foot thickness of target zone to be stimulated following the same technique used on previous acid jobs conducted by PNOC-EDC. Injection of the mainflush was preceded by a preflush solution of 10%HCl, the volume of which is equivalent to 50 gallons per foot of payzone for a 75 gal/ft mainflush dosing rate. The permeable zones in the openhole were also acidized after the casing perforation to remove the formation damage caused by the drilling mud.

3.2 Stimulation results

Comparison of the downhole measurement before and after casing perforation and acid treatment enabled PNOC-EDC to assess improvement in the wellbore. Improvement indicators used in the analysis of the stimulation results include changes in location and approximate thickness of permeable zones, increase in the injectivity index and other permeability parameters, reduction in wellbore and/or pumping pressures during the tests, and a more pronounced temperature kick across confirmed payzones.

Table 1 clearly shows the progressive wellbore improvement brought about by the stimulation job. The observed increase in the permeability of the well between its original completion and the test done before the perforation job might have been the result of several clearing discharges on the well. It nevertheless remained damaged as indicated by its positive skin taken during the two tests.

Table 1: Improvement in the wellbore from the time the production casing was perforated to the final acid treatment (Malate et al., 2000).

Parameters	Injectivity Index (li/s-MPa)	kh (d-m)	Skin
Original	21	20	27
Pre-Perforation[a]	40	24	27
Post-Perforation Post-Acid[a] plugged	61[b]		
Post-Perforation Pre-Acid openhole	70 99[b]		
Post-Perforation Post-Acid	124 215[b]	30	-5.6

Notes
[a] Completion conducted using PATS tool, the rest with Kuster.
[b] All measurements taken at 1500 mMD (meters Measured Depth) except those marked b.

The calculated injectivity index increased to 70 li/sec-MPa with vacuum wellhead pressure after the casing perforation. The final injectivity test conducted in the well after the casing perforation and acid treatment of the permeable zones was found to be around 215 li/sec-MPa. This value is higher than the baseline injectivity index of the well at 40 li/sec-MPa.

Figure 4 also illustrates the combined effect of casing perforation and acid treatment of the perforated intervals. The abrupt change in the pressure gradient around 700 mMD (meters Measured Depth), accompanied by a steep spinner response (rps) and deflection in the temperature profile of the well during pumping tests have been observed in past measurements of wells with confirmed gas or steam entry into the wellbore. Therefore, it is postulated that during this test (Figure 4), the perforated interval around 700 mMD was feeding two phase fluid, and possibly gas, which was immediately quenched by continuous

injection of cold water. This is also suspected to have led to the failure of the injectivity test after the casing perforation job. Minimal relative acceptance of injected water at the perforated interval around 730-739 mMD and at 956-965 mMD is manifested in the spinner log. Major permeability on the other hand is indicated by the spinner and temperature profiles across the perforated intervals between 1050 and 1073 mMD.

The specific contribution of either the casing perforation or the subsequent acid treatment of the perforated intervals could not be determined. An injectivity test was attempted right after the perforation job, with the tool set close to the shallowest perforation interval. The test failed with a negative injectivity slope, which is attributed to the possible collapse of the two-phase column during pumping.
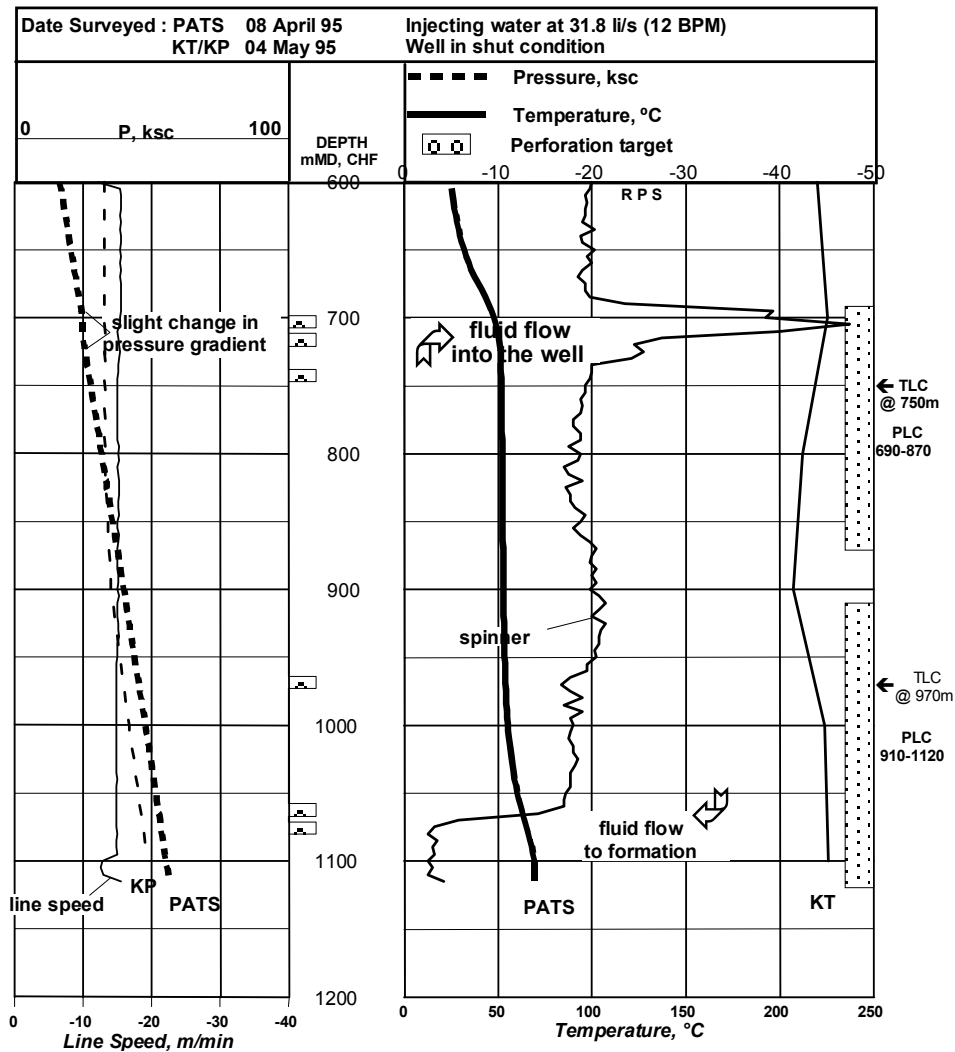

Figure 4: Results of post-perforation Completion Test with bridge plug set near the production casing shoe (Malate et al., 2000).

A post-acid spot discharge test conducted in the well produced an output of around 4.3 MWe or a 430% increase in power output at the desired operating wellhead pressure of 1.02 MPag. The well was unable to attain this output prior to the stimulation with the maximum discharge pressure reaching only 0.95 MPag. The significant increase in power output suggests successful stimulation of the damaged permeable zones and the perforated sections.

However, the minimal improvement in discharge enthalpy was below expectations and discharge data suggests that the bottom feed zone was masking the two-phase feed

contribution from the perforated production casing (Table 2). Temperature-pressure-spinner (TPS) surveys conducted at flowing conditions confirmed the immense liquid input from the open hole and the lower perforated section, and the relatively small two-phase contribution from the upper perforated zones. Wellbore simulation was then performed to evaluate the optimum utilization of the well by controlling the bottom low enthalpy liquid feed zone and maximizing the contribution from the upper two-phase zone (Molina et al., 1998). It was determined that higher steam and mass flows can be attained by eliminating the bottom zone.

Table 2: SK-2D bore output summary (Molina et al., 1998).

Wellhead Pressure (MPag)	Mass Flow (kg/s)	Enthalpy (kJ/kg)
0.70	72.1	1155
1.10	36.8	1107
1.70	19.0	1266
1.90	12.3	1276

4 Casing repair

PNOC-EDC experiences have revealed that casing damage (break) usually occurs in wells with poor cementing or with trapped water behind the casing that could thermally expand during discharge causing the casing to burst. The usual remedial action undertaken involves milling the damaged casing and squeezing cement behind the casing. Another remedial measure in more problematic cases is running a blank sleeve inside the casing to seal off the damage. This option would have to be weighed with the possible reduction in well output due to the drop in massflow inside the new casing.

Liner breaks have also known to occur in some wells due to corrosion, material failure, or inadequate liner design. This problem is usually addressed by running a liner sleeve, which would protect the well from formation collapse. PNOC-EDC has sometimes left some wells with liner damage if their outputs were not affected by the break. The disadvantage of leaving the well is that downhole surveys can no longer be conducted to check the well condition.

Excessive wellhead rise also occurs in some wells due to the thermal expansion of the anchor casing during discharge. This problem is normally caused by poor cement condition behind the anchor casing and remedial measures also involve squeeze cementing and possibly relining the well with the wellhead assembly attached to the original production casing which will then become as the new anchor casing.

Generally, PNOC-EDC conducts multi-finger Casing Inspection Caliper (CIC) runs to establish if the casings are still within safe operating conditions. In some cases, these logs are conducted in light of damage to wellhead components caused by suspended solids during discharge such as a) thinning of wellhead tee and bends, b) piles of solids found in separators, and c) holes in sacrificial valves. CIC logs provide advance information on internal casing damage or abnormality, which can lead to costly revenue losses due to shutdowns and well repairs. Figures 5, 6 and 7 show typical signatures of CIC logs where casing thinning caused by corrosion and erosion, scales buildup and casing break (holes) are obtained. An audit of the actual casing weights against casing tally is also obtained from the CIC logs.
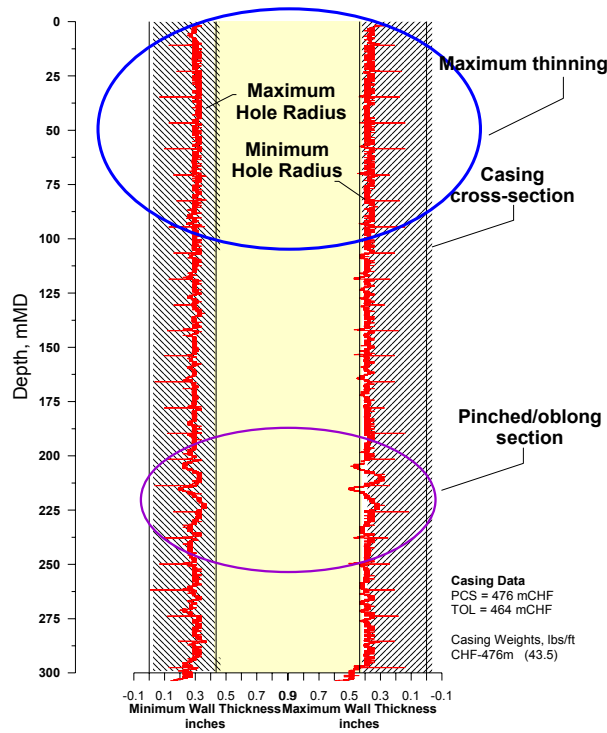
Figure 5: Well 401 casing caliper log showing thinning of the production casing (Buñing, 2003).
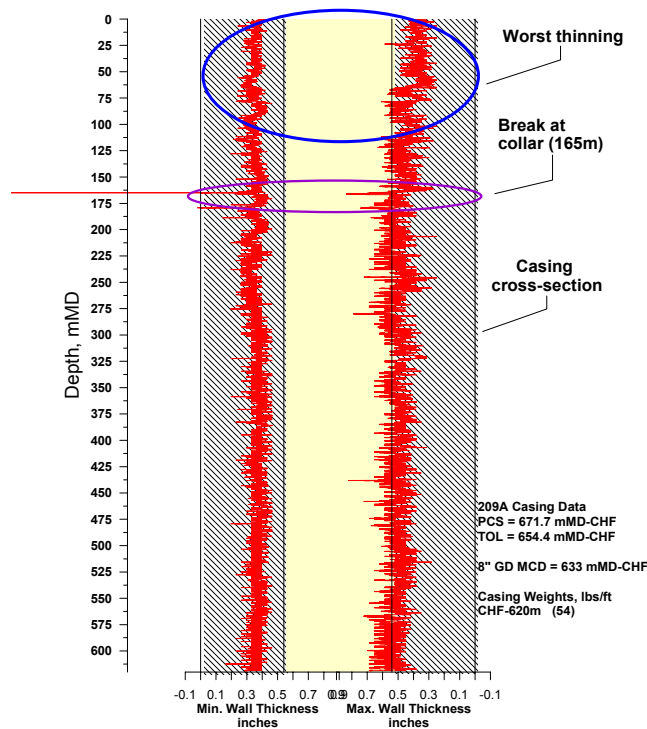

Figure 6: Well 209A casing caliper log showing thinning of the production casing and casing break at the collar (Buñing, 2003).
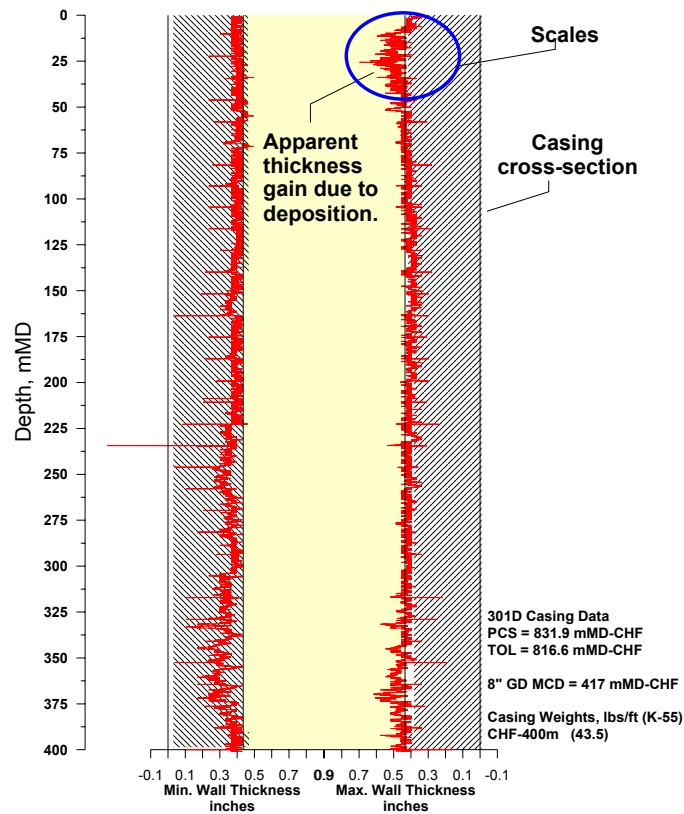
Figure 7: Well 301D casing caliper log showing scales buildup (Buñing, 2003).

5 Zone plugging

This well intervention essentially eliminates the permeable zone(s) that affect the performance of the well. These permeable zones may have been affected by inflow of cool injection fluids and are usually plugged with cement. The success of eliminating these zones also hinges on the ability of isolating the annular space between the liner and the formation prior to cement plugging. Figure 8 shows an example of a well profile before and after the bottom zone plugging was undertaken, and its effect on the output as shown in Table 3 (Sarmiento, 2000). The output of the well (APO-2D) was non-commercial due to the low enthalpy contribution of the bottom major feedzone. The well produced a commercial output after plugging despite the reduction in the total massflow.

Zone plugging is also conducted in wells to isolate acid inflows at certain feed zones. A careful assessment of the feedzone to be isolated is undertaken in terms of the extent of the acid inflow to the neighboring wells to establish the viability of the plugging operation in the long-term performance of the wells.

Table 3: Well APO-2D output before and after bottom zone plugging (Sarmiento 2000).

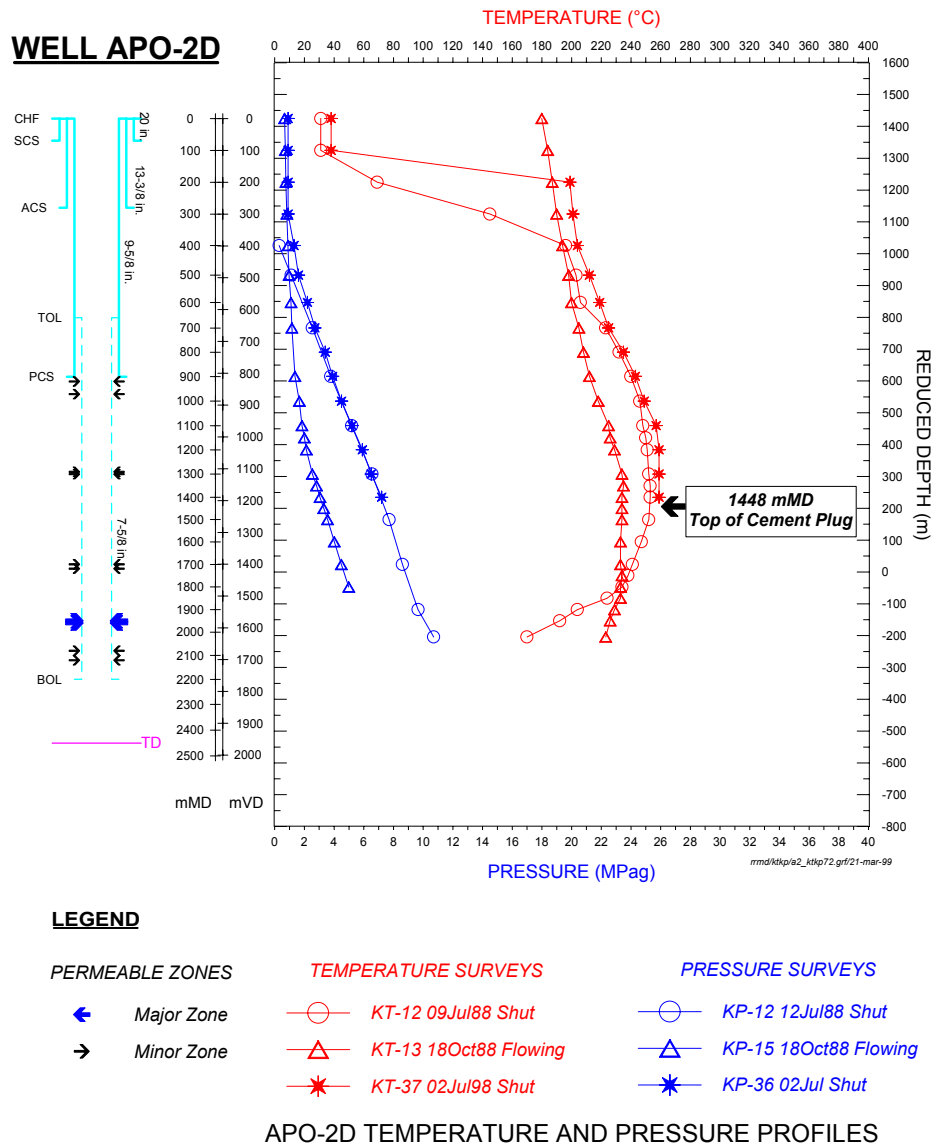| WHP (MPag)	Massflow (kg/s)	Enthalpy (kJ/kg)	Power (MWe)	Remarks
0.54	37.6	964	Non-com	Output before zone plugging
0.53	17.1	1665	3.8	Output after zone plugging

Figure 8: Well APO-2D downhole profile before and after plugging (Sarmiento, 2000).

6 Well deepening

Wells are normally deepened to access additional zones that will give more steam or injection capacity. This option is considered when there is an expected improvement of capacity with the intersection of additional permeable structures at a deeper level. Moreover, this alternative is more economical than drilling a new well.

7 Wellbore acid treatment

The main objective of this well intervention is to increase production or injection capacity of the well. The productivity or injectivity is generally improved in two ways: (1) removing formation damage (mud or mineral deposits) and increasing the permeability in the vicinity of the wellbore; and (2) creating a conductive fracture extending from the wellbore into the reservoir, to increase the effective wellbore radius. The first method is normally called *matrix acidizing* and the second one is *acid fracturing*.

7.1   Matrix acid stimulation

Matrix acid stimulation is a chemical stimulation method in which the acid removes the damage or filter cake that extends beyond the immediate surface of the perforations, (or the face of the producing zone), and increases the permeability near the wellbore. The acid acts by dissolving minerals that make up the original formation matrix, as well as pore-plugging contaminants that result from mud invasion or fines (silt) migration. The acid is injected into the formation at pressures considerably less than the formation fracturing pressure that results to *radial flow* into the formation (Economides and Nolte, 1989).

The acid enters the rock and flows through the natural pores and flow channels, reacting with the walls of the pores and flow channels and enlarging them (See Figure 9). Because the contact area between the acid and the formation is usually very large, matrix acid jobs are therefore conducted at low injection rates. The acid also reacts with clay materials attached to the walls of the pore spaces and with invading fines (silt) and clay particles trapped in fissures (veinlets). The chemical reaction between the penetrating acid and the formation gradually slows down as the acid is spent, until the reaction is finally completed.
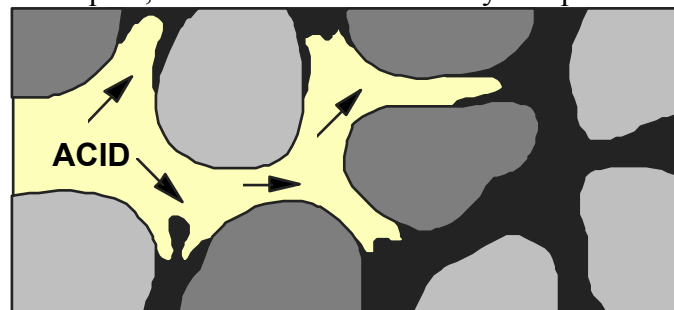

Figure 9: A matrix acidizing treatment where the acid penetrates into the pore spaces of the rock without fracturing the formation (Hibeler and O'Driscoll, 1996).

The treating rate is increased whenever possible, proportionally to the permeability improvement during the acid job, thereby keeping a constant downhole injection pressure. This will improve zone coverage and increase acid penetration.

A matrix acidizing treatment may only penetrate a few inches into the formation, or it can be effective up to ten to twelve feet from the wellbore, depending on the formation permeability. For wells that have suffered extensive near wellbore skin damage, productivity (or injection capacity) will increase manyfold. However, if a well had little or no skin damage, an acid treatment would stimulate natural production by a marginal value depending on the acid job design. Matrix acidizing is generally designed to create a front of reacting acid that will reach the estimated radius of formation damage. Acid treatment is also designed so that the chemical reaction will restore the original undamaged formation permeability. It is not generally intended to affect a radius beyond the damage zone.

7.2   Acid job planning and design

In designing an acid treatment, several basic factors are considered such as: a) type of damage (mud); b) acid solubility of the formation; c) type of formation; and d) the length of perforated or openhole interval (Williams et al., 1979). These factors coupled with reservoir data such as porosity and permeability are normally used in designing the type of treatment method.

A typical acid treatment is commonly performed in three stages:
1.   A preflush, usually by hydrochloric (HCl) acid.
2.   A mainflush hydrochloric (HCl)-hydrofluoric (HF) acid mixture treatment.
3.   A postflush/overflush usually by either HCl, potassium chloride (KCl), ammonium chloride (NH$_4$Cl) or freshwater.

The use of HCl as a preflush displaces the formation brine and removes the calcium and carbonate materials in the formation. The preflush acid also minimizes the loss of the hydrofluoric acid used in the second phase of the treatment and also serves as a spacer between the HCl-HF acid and the formation water. Brines and seawater are never used to prepare this treating fluid, as the metal ions present in solution, can react to form precipitates with hydrofluoric acid

The acid mixture of HCl-HF is used to react with the rock matrix and formation damage. These HCl and HF acids are often used as mixtures for the simple reason that HCl is effective at dissolving limestone and dolomite. Hydrochloric acid is largely ineffective at dissolving siliceous minerals such as clays, feldspars and silica sand. On the other hand, HF acid is effective on siliceous minerals, yet, it is ineffective on carbonates because its reaction forms an insoluble precipitate.

A postflush/overflush is pumped after the main acid treatment to displace the reaction products away from the wellbore and reduce the possible precipitation damage. The most common of these are usually either HCl, potassium chloride (KCl), ammonium chloride (NH_4Cl) or freshwater.

In oil and gas reservoirs, matrix acid treatment is commonly performed with typically 12%HCl-3%HF (normally called "mud acid") since the majority of the wells are cooled down to lower temperatures (~40^oC) during stimulation. The same acid mixture at slightly different concentration (10%HCl-5%HF) is also used in the Philippines in treating mud damaged geothermal wells. A slightly higher concentration of HF acid is used to accommodate the extra minerals (i.e. silica) found in the formation.

It should be noted here that excess HCl is present in the HCl-HF acid mixtures with the sole purpose to increase the solubility of byproducts of the reaction with formation minerals thereby minimizing the precipitation of Ca^{++}, Na^{+}, and K^{+} fluoride salts (Stimulation Technical Review, 1994). The HCl dissolves the hydrochloric acid-soluble material and thus prevents the hydrofluoric acid from spending too rapidly.

There are several studies for oil and gas reservoirs that have been conducted on acid volume optimization. The general consensus from published literature is that acid jobs using less than 75 gal/foot of payzone thickness are about 30% successful, while jobs where 75-125 gal/foot of payzone thickness is used have a success rate of 75%. Acid jobs of over 200 gal/foot have had good results (>75%), but few have been done due to cost considerations. Table 4 below provides a rule of thumb volume recommendation based on permeability. Field studies have shown that the best acid job results occur on reservoirs with permeability of 5md or higher.

Table 4: Empirical acid treatment volumes based on permeability (Hibeler and O'Driscoll, 1996)

Avg. Permeability Without Damage K (md)	Normal HCl Gal/ft	Normal HCl:HF Gal/ft	Remarks
< 0.1 md	15-25	Not Recommended	a, c, d
0.1 - 2.0 md	25-50	Not Recommended	a, c, d
2.0 - 10 md	35-75	75-100	c
10- 50 md	50-100	100-150	c
> 50 md	50-100	100-200	b

a. Volumes should be selected based on core tests.
b. Volumes can exceed 100 gallons per foot if necessary without releasing excessive fines.
c. Volumes can be modified if indicated by field test results.
d. Use acid for perforation cleaning only.

Where the formation damage is suspected to be shallow (0 to 2.0 feet), an ***estimate*** of the treating volume of acid required can be obtained from Figure 10 based on treating radius and formation porosity.
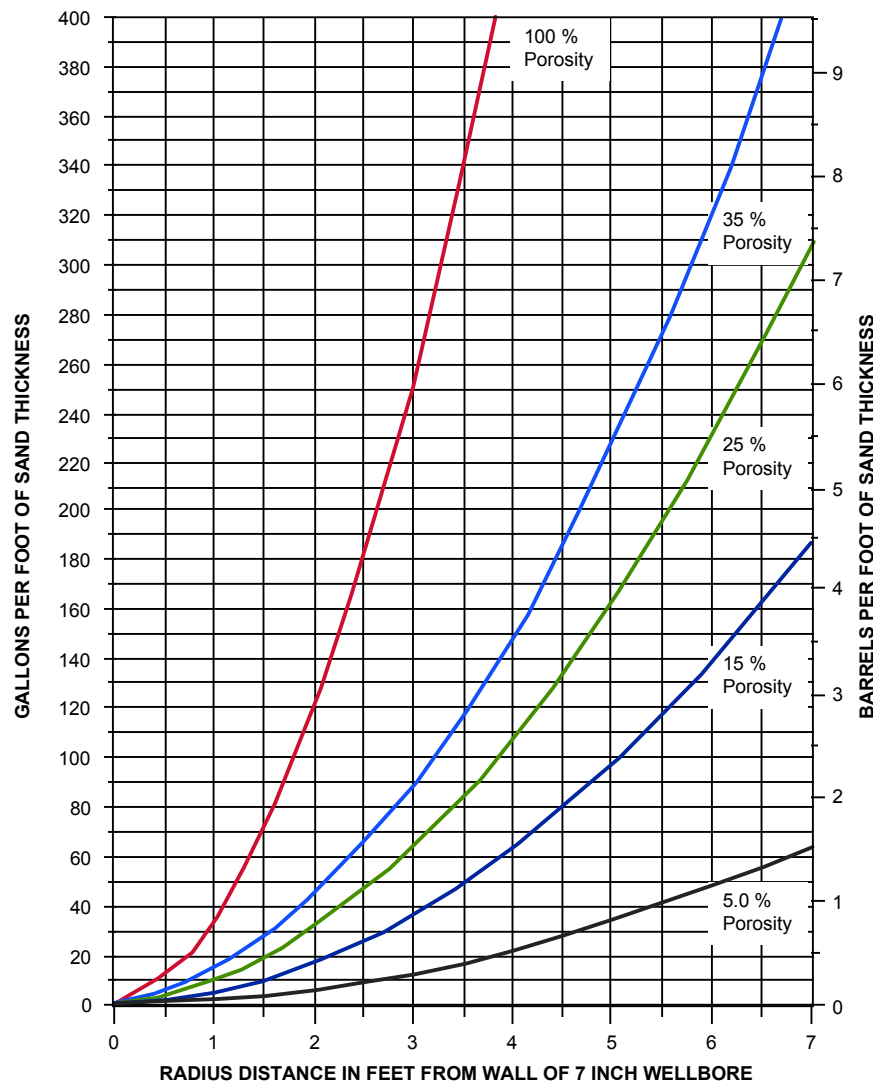

Figure 10: Gallons per foot of treating fluid for different formation porosities (Hibeler and O'Driscoll, 1996).

A more efficient way of designing acid volume (instead of porosity and permeability "rules of thumb") is by dissolution test of the scales samples obtained or standard core dissolution (coreflow) tests in the laboratory. In order to optimize the strength of HCl:HF mixtures used in matrix stimulation, core flow tests are carried out with different hydrochloric and hydrofluoric acid mixtures. These tests are run using representative cores and fluids at simulated bottomhole conditions.

Acid dissolution tests on scale samples should at least be carried out in designing acid volumes, and laboratory flow tests on representative cores and fluids at corresponding temperatures should be conducted whenever possible.

7.3   Basic acid job design

As discussed in the previous section, the design of a typical acid treatment job is usually based on the results of *dissolution tests of the scales samples* obtained or standard core

dissolution (*coreflow*) tests in the laboratory. If representative cores are not available, the acid volumes and concentrations can be also initially estimated from formation solubility analysis, permeability and porosity correlations of known reservoirs.

A matrix acid stimulation procedure can be applied where a treatment design criterion of 75 gallons of mainflush acid per foot of payzone interval is initially suggested. This criterion is based on industry experience in the oil and gas well stimulation and serves also as a reasonable estimate for geothermal wells. This basic design has also been applied in the majority of acid stimulation jobs in the Philippines with considerable success (Buñing et al., 1995; Malate et al., 1997; Malate et al., 1998; Malate et al., 1999; Yglopaz et al., 1998).

Here, a 10%HCl-5%HF mainflush acid concentration for the ***mud damaged candidate wells*** can be programmed and maybe fine tuned depending on the results of the scales dissolution tests. Injection of the main acid is preceded by a preflush solution of 10%HCl to dissolve the iron and carbonate materials that may later deposit insoluble minerals (CaF_2 for example) with the HF acid and will serve as a spacer between the mainflush and the formation brine. A 50 gallons per foot of payzone thickness of preflush volume is also programmed for the wells.

A small volume of KCl postflush solution to reduce possible precipitation damage then follows the mainflush acid. Freshwater overflush is then injected for displacing the acid treating solution and rinsing the tubular and metal casings of unspent acid in the wellbore. Its volume is estimated to be at least twice that of the acid mainflush.

Corrosion inhibitors and intensifiers are also added to the acid mixtures (preflush and mainflush) to reduce the corrosion rate of the well tubulars and equipment by the acid. A corrosion loss rate of not more than 0.05 lbs/ft^2 is applied as a standard for the acid treatment job. The allowable corrosion rate should be attained for an exposure time of at least 12 hours at downhole conditions of at least 100°C.

Chelating or sequestering agents can be used to address possible precipitation of iron soluble materials from surface equipment and tubulars as well as iron bearing minerals in the formation. The iron content of the acid mixtures and in the reservoir fluid should be established prior to acid injection to warrant the application of these sequestering agents. The total iron content can be determined from spent acid returns of previous acid jobs. Total iron in parts per million divided by five will give an estimate of the ferric iron content (Hibeler and O'Driscoll 1996). In some cases, iron scales initially found inside the tubings are cleaned with a "pickling" treatment prior to pumping of the acid.

Acid injection rate is maximized whenever possible for deeper penetration of the live acid due to the fast reaction rates of HCl acid with carbonates and HF acid with mud present in the formation. Since high injection rates customarily involve high pressures, the formation is likely to be fractured during such treatments. A more complete coverage can also be obtained using high acid injection rates for wells having multi-zone targets where several permeable zones accept fluid at different downhole pressures.

7.4 PNOC-EDC experience

Injection wells have commonly been primary candidates for stimulation when PNOC-EDC started to undertake its acid stimulation program in 1993. The majority of these injection wells were stimulated due to formation damage caused either by silica deposition in and away from the wellbore or mud during drilling. Significant improvement in their capacities was attained after the acid treatment. Some of the experiences gained in acidizing these wells including the refinements made in improving the acid treatment are discussed below.

7.4.1 Leyte Geothermal Power Project

The development of the entire Leyte Geothermal Power Project (LGPP) in 1995 experienced a shortfall in injection capacity, particularly in the Mahanagdong and South Sambaloran sectors of the field. Initial analysis of the wells drilled in these areas identified injection wells 4R7D and 4R12D in South Sambaloran and well MG-7RD in Mahanagdong that may have been damaged by mud during drilling. PNOC-EDC programmed these wells for acid stimulation to improve their injection capacities, thereby reducing if not eliminating drilling of new injection wells (Malate et al., 1997).

Well 4R7D was drilled in 1995 to a total depth of 2,492 mMD while 4R12D was completed in 1996 to a depth of 2,624 mMD. These wells, although targeted in the more permeable sector of South Sambaloran, have shown marginal injection capacities. The injection capacity of 4R12D in fact was unexpectedly low compared with the other big holes drilled in the area. MG-7RD is another injection well in the Mahanagdong area, completed in 1995 with a total depth of   1,815 mMD. Its estimated injection capacity was also found to be low compared to its neighboring wells.

All three wells were initially postulated to have been damaged by mud during drilling. Examination of their drilling records revealed that significant amounts of highly viscous mud (HVM) were injected into the open hole section of these wells, causing restrictions to flow and resulting in poor injection capacities (See Table 5). This became the primary consideration in selecting these wells as candidates for acid stimulation.

Table 5: Mud volume lost during drilling.

Well	Total Mud Lost (barrels)
MG-7RD	7,210
4R7D	17,735
4R12D	21,329

Well 4R7D could have even incurred further damage when it was briefly used for injection of sump fluids during the drilling of its neighboring wells. An evaluation was then made to determine if such damage existed, how significant it was, and how acid stimulation could significantly improve the wells' performance.

The major permeable zones found in these wells are postulated to have accepted most of the mud lost since these would have the least resistance to flow and so the greater capability of accepting the mud. Acid treatment of these payzones could substantially reduce if not eliminate the damage, thereby clearing the fluid flow paths and improve the acceptance of the wells. These payzones can be initially identified from drilling circulation losses correlated with geological and petrologic records. To further refine the definition of such zones, downhole surveys and well test results were utilized. These measurements are also intended to constitute the baseline data from which improvement in the wellbore due to acidizing might be gauged.

The results of the pre-acid PATS survey in 4R7D showed a thin major permeable zone starting from 1,980 mMD where the spinner response starts to sharply decrease (Figure 11). This was matched by the temperature gradient that began to change from this depth and increased towards the bottom. Minor permeable zones appeared at around 2,080-2,120 mMD and at   2,260 mMD to bottom. The temperature near the bottom remained steady even with increased pumping, unlike at shallower depths which expectedly cooled suggesting that most of the fluid was lost at shallower levels.

A major permeable zone at around 1,650-1,790 mMD was distinguished from the logs in well 4R12D (Figure 12). A minor zone appeared likely at around 2,550 mMD to bottom. These zones were marked by a drop in spinner response that was interpreted as fluid loss zones. Kuster surveys at MG-7RD showed sharp increases in temperature at 1,250-1,300 mMD, 1,650-1,750 mMD and 1,800-bottom which indicated permeable zones at these depths (Figure 13). This was evident from the waterloss profile and even more prominent from the zero flow profile recorded.

Well data from injection and pressure transient tests were analyzed to determine parameters such as injectivity, transmissivity, storativity and skin, which are essential in the evaluation of the acidizing candidates. The well test interpretation software Saphir (Kappa Engineering, 1995) was used for the analysis. Saphir enables a computer-aided approach to pressure transient analysis, automating such procedures as type curve matching and pressure derivative generation. Furthermore, the data can be easily tested under various combinations of well/reservoir models and boundary conditions so that the most appropriate conditions could be determined. For the wells in this study, a homogenous reservoir model with an infinite boundary and wellbore storage and skin was found to be appropriate. Results of the pre-acidizing pressure transient analysis are summarized in Table 6 below.
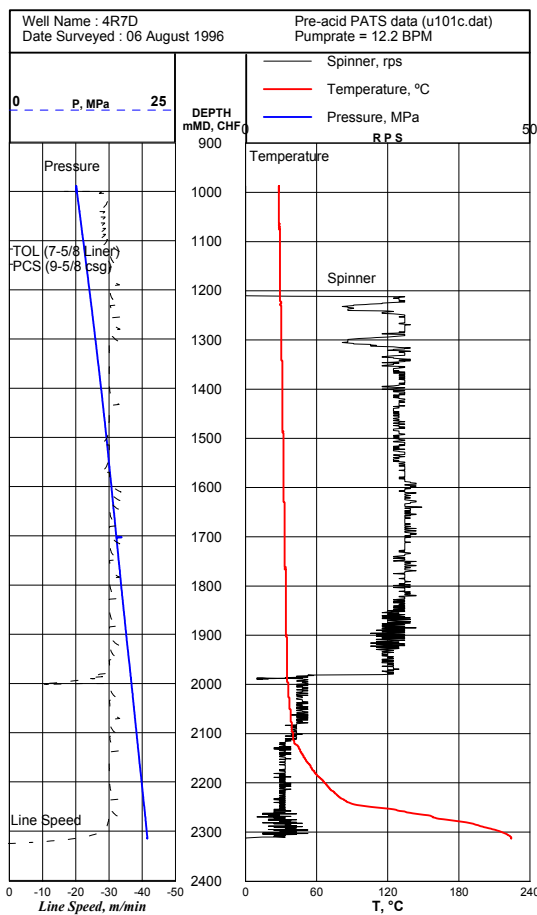

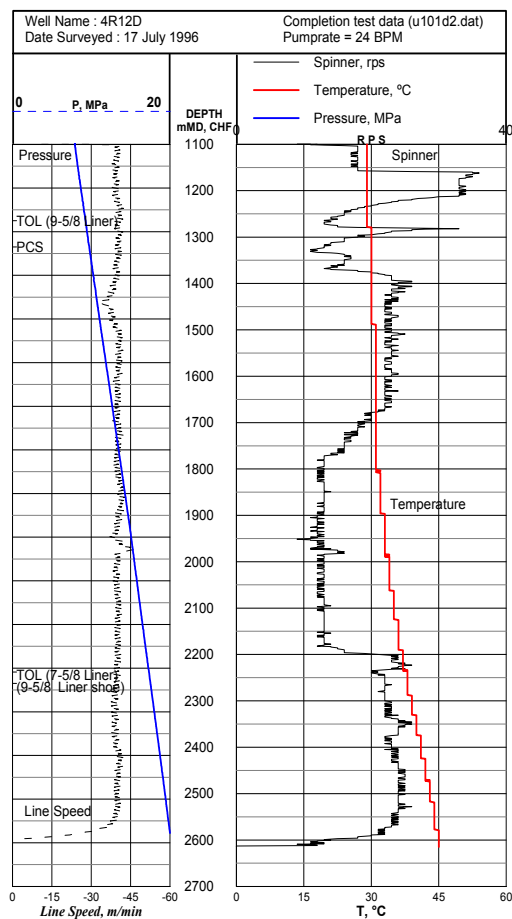**Figure 11: Pre-acid PATS log of well 4R7-D**

Figure 12: Pre-acid PATS log of well 4R12-D

Table 6: Summary of pre and post-acid well test analysis results (Malate et al., 1997).

|	MG-7RD		4R7D			4R12D	
	Pre-acid	*Post-acid*	*Original*	*Pre-acid*	*Post-acid*	*Pre-acid*	*Post-acid*
Date Tested	17-Sep-95	24-Dec-95	7-May-95	5-Aug-96	11-Aug-96	16-Jul-96	3-Sep-96
Injectivity Index (li/s/MPa)	15.4	114.0	12.7	6.8	17.7	30.1	58.4
Injection Capacity (kg/s)	81	370	70	36	91	149	264
Transmissivity (darcy-m)	2.8	11.3	2.2	1.1	2.8	9.6	14.8
Skin	+6.2	-2.2	-0.7	+3.2	+1.8	+9.9	+1.0
Storativity (m3/kPa)	0.0109	0.0159	-	0.0062	0.0128	0.0128	0.0258
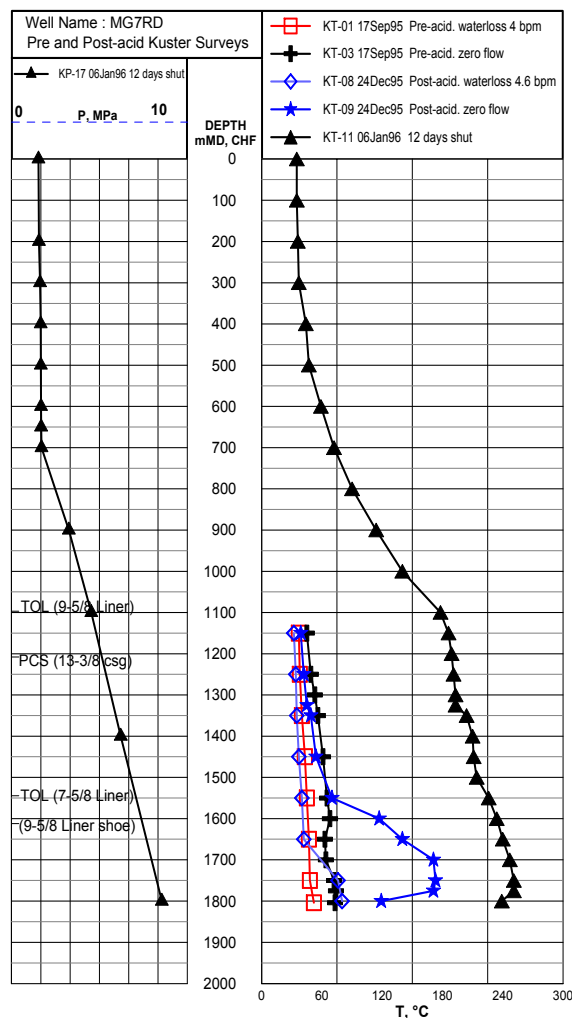
Figure 13: Pre and post-acid temperature and pressure profiles of MG7R-D (Malate et al., 1997).

All the wells showed good permeability based on the transmissivity values derived, which indicated favorable acceptance. However, the injectivity that reflected the downhole pressure response to injection was relatively low, particularly for MG-7RD and 4R7D. The true

acceptance of the wells was therefore not being attained, likely due to mud damage. The high positive skin values obtained also supported the postulated damage initially created by the mud. Well 4R7D also exhibited an apparent decline in injection capacity prior to acid treatment as shown by the higher skin value and a significant drop in injectivity. This was likely the effect of its use for waste fluid injection after drilling. The results obtained from these welltest surveys have further reinforced the selection of these wells for acid stimulation.

A matrix acid treatment procedure was applied for all the wells as in the previous acid jobs of PNOC-EDC. A mixture of 10% hydrochloric acid (HCl) and 5% hydrofluoric acid (HF) was also used as the mainflush, which was primarily intended to dissolve the silicate and carbonate deposits. The mainflush volume was based on a dosing rate of 75 gallons per foot of target payzone. A preflush solution, injected prior to the mainflush, was also prepared consisting of 10% HCl. This removed the acid soluble deposits, minimized the loss of HF in the mainflush, and served as a spacer between the mainflush and the formation brine. The preflush volume was based on a dosing rate of 50 gallons per foot of target zone. The target payzones were determined from the permeable zones identified from the pre-acid completion tests.

The acid treatment was conducted by injecting the appropriate acid mixtures through an open- ended drill string set at the targeted payzones. A combination of 5", 3" and 2-7/8" drill pipes were utilized. Preferably, the drill pipe sizes to be used should be maximized for better hydraulic efficiency. The injection process in this case was modified into stages so that the treatment could be applied more evenly across the payzones, particularly for wells with multiple zones. This was done by segmenting the target zones into smaller sections (e.g. 50 meters) and treating each zone separately. The end of the drill string was spotted just above each section and correspondingly, the calculated volume of the acid injected into the section. Treatment started from the topmost target zone going down until the deepest zone. The injection rate was kept as high as possible below the calculated fracture pressure gradient to achieve better acid penetration into the desired targets.

An attempt to temporarily isolate the targeted payzone from the other zones of interest was applied in well 4R7D by using diverting agents. Benzoic acid flakes were initially used as the chemical diverting agent to determine its applicability. This chemical diverter is also used to achieve uniform placement of the stimulation fluid. The volume of diverter used was based on a dosing rate of 5 lbs of benzoic acid per foot of payzone. The diverter was injected prior to the preflush acid at every stage.

7.4.2 Stimulation results

Post-acid completion tests were conducted on these wells to determine improvement in the wellbore in terms of injectivity indices, changes in temperature and pressure profiles and payzone thicknesses and other reservoir parameters. These are basically waterloss, injection and pressure transient tests patterned after the pre-acid completion tests. The PATS logging tool was also used in wells 4R7D and 4R12D, while Kuster temperature and pressure gauges were used in well   MG-7RD.

Results of the post-acid PATS survey in 4R7D showed a clearer definition of the permeable zones starting at 1,980 mMD compared to the pre-acid logs (Figure 14). The section from 1,980 to about 2,100 mMD now appeared to be composed of several discrete sections whereas before, only a thin zone near 1,980 m was distinguished. Based on spinner responses, permeable sections were now discerned at around 1,980-1,985; 2,030-2,035; 2,100; and 2,210 mMD, with the last two sections appearing as minor zones. This indicated an opening up of previously blocked zones and clearing of fluid flow paths. Temperatures close to the bottom declined with increased injection unlike at shallower depths, which expectedly cooled. This suggested that the majority of the injected fluid was accepted at shallower levels (above 2,330 mMD) thereby hardly affecting the temperatures close to the bottom. The

prominent increase of the temperature gradient which started at 2,100 mMD during the pre-acid completion tests, now began lower at 2,240 mMD. This could be attributed to the clearing and opening up of zones above 2,240 mMD.
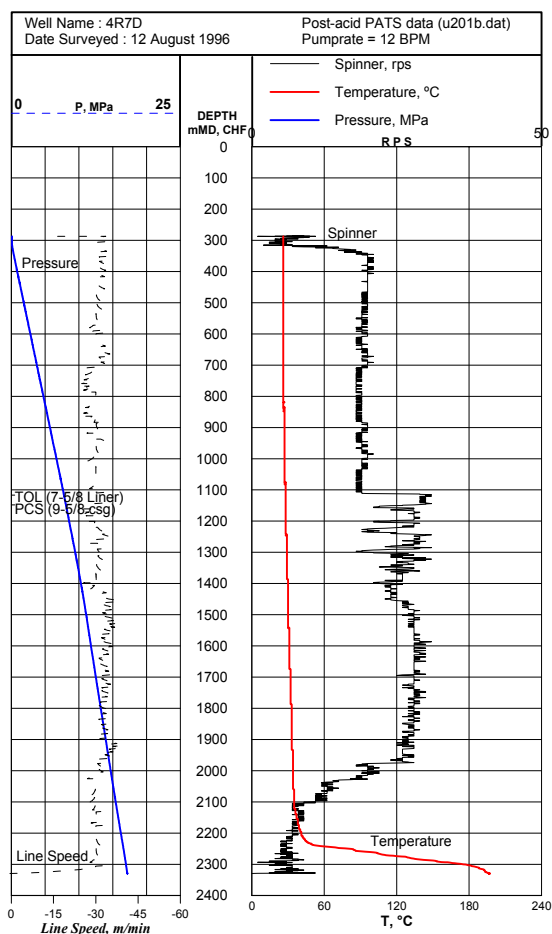

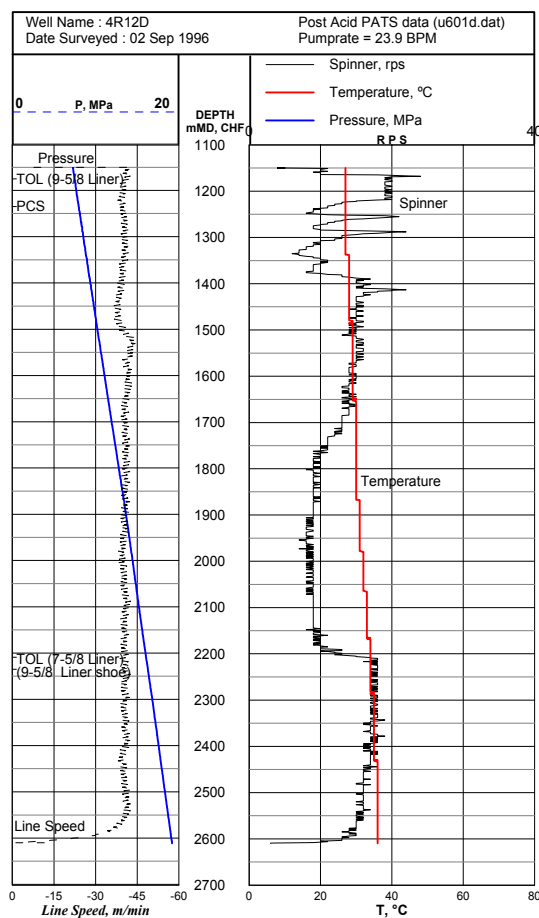**Figure 14: Post-acid PATS log of well 4R7-D**   **Figure 15: Post-acid PATS log of well 4R12-D**

The effect of the chemical diverter was not determined with certainty. However, the appearance of discrete permeable sections within the treated payzones can be attributed to the more evenly distributed acid treatment perhaps made possible by the diverter.

The post acid completion test results for well 4R12D are presented in Figure 15. The permeable zones identified are similar to the pre-acid logs recorded except for a newly observed thin zone at around 2,450 mMD. The slight increase in the temperature gradient starting at about 1,800 mMD coincided with the occurrence of the major permeable zone (1,650-1,790 mMD).

The temperature profile obtained from the post-acid Kuster surveys in MG-7RD showed a more distinct major permeable zone at around 1,650-1,750 mMD (Figure 13). The increase in the temperature gradient around this depth was more pronounced compared to the pre-acid profiles as shown by the waterloss and zero flow surveys. Again, such a change could be attributed to the opening of zones previously obstructed.

The three wells also registered a decline in downhole pressures during the post-acid injection tests. The observed decline ranged from about 1 MPa seen in 4R12D to around 3.5 MPa in 4R7D. This signified a reduction in pressure resistance against injection that meant restriction to flow was lessened and hence better acceptance.

A decline in water levels during injection was also observed in 4R7D and 4R12D. The water level in 4R7D reached a depth of 250 m while injecting at a maximum rate of 17 bpm

during the post-acid tests compared with the water level recorded at 260 m during the pre-acid test at an injection rate of only 5 bpm. Similarly, the water level in 4R12D declined to about 450-470 m at 6-18 bpm compared to about 360-415 m at 6-12 bpm. This decline in water level was indicative of improved acceptance.

Post-acid pressure transient data were also analyzed using the welltest simulator Saphir. The results are also summarized in Table 5. Significant improvements in well characteristics were attained after the acid treatment, as indicated by results of the post-acid well test analysis. Transmissivity values of all the wells appreciated, most remarkably in MG-7RD and 4R12D. Enhanced storage capacity was realized with the improvement in storativity. High positive skin values were reduced, although only at MG-7RD was a negative skin achieved. The skin values of the other two wells were now only slightly positive. The damage attributed to mud was apparently reduced substantially if not completely eliminated. Increases in injectivity were achieved, by as low as 10 kg/s/MPa for 4R7D to as high as 104 kg/s/MPa for MG-7RD. Along with the decline in downhole pressures, this resulted in an overall improvement in injection capacity by a minimum of 55 kg/s for 4R7D and a maximum of 289 kg/s for MG-7RD. In relative terms, injection capacities increased from 113% for 4R12D to 357% for MG-7RD.

7.5 Bacman geothermal production field

The Bacman 1 power plant in the Bacman Geothermal Production Field (BGPF) will be on full load operation after the completion of repairs on turbine generator unit 2 by March 2003. All the available production wells will then be put on line to support the full load operation that would give an estimated brine load of 405 kg/s. The total injection capacity in the area stands at   294 kg/s due to the recent decline in the injection capacity of PAL-1RD due to silica deposition. The well's injection capacity has steadily declined from the original capacity of 216 kg/s in 1998 to the present capacity of 132 kg/s in January 2003 (See Figure 16).
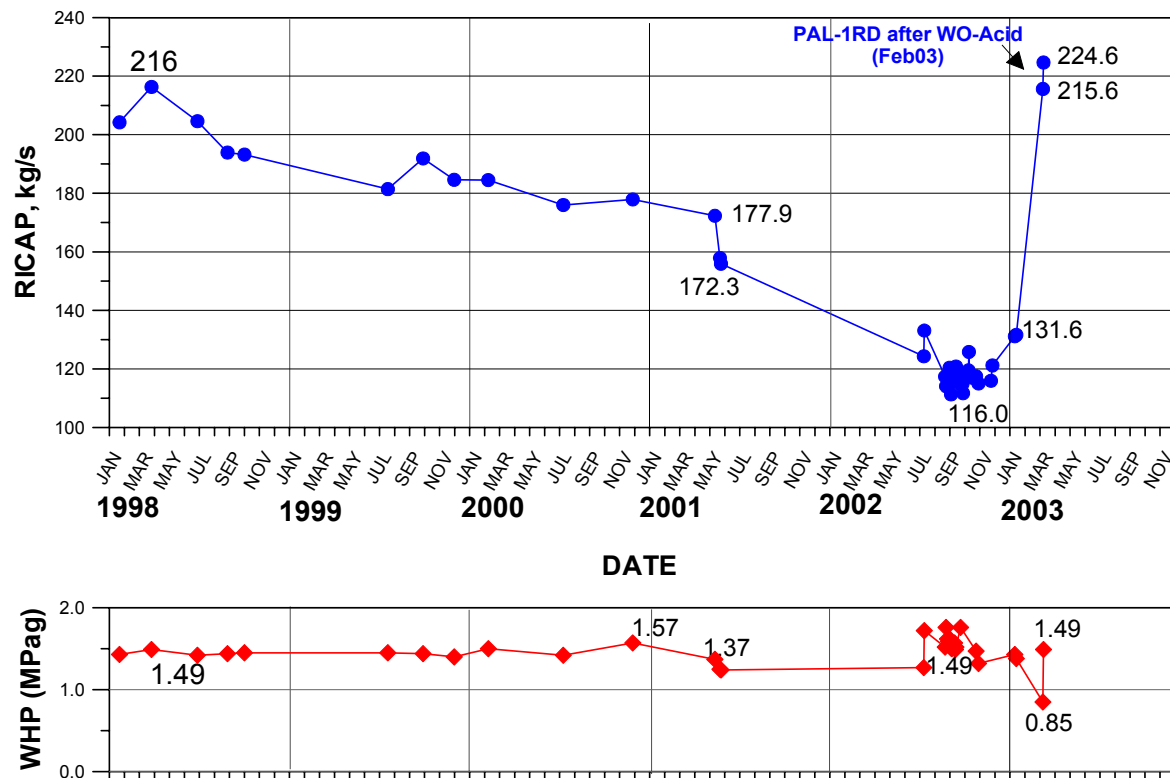

Figure 16: Well PAL-1RD injection capacity with time.

PAL-1RD was then programmed for workover and acid stimulation in February 2003 to clear and dissolve the silica deposits around the wellbore and permeable zones. The improvement to be gained from the workover and acidizing of PAL-1RD will help address the expected shortfall in the total injection capacity of around 111 kg/s.

A matrix acid treatment procedure was also conducted in the well with similar acid job design criteria used in treating mud damaged injection wells. The results of the acid treatment gave a significant increase in injectivity from a pre-acid value of 47 li/s-MPa to post-acid injectivity of 174 li/s-MPa. The downhole pressures after acid treatment dropped by about 0.5 MPa that signified a reduction in pressure resistance against injection. The present injection capacity of the well now stands at around 225 after the acid treatment as shown in Figure 16.

7.5.1   Wellbore soaking

The Botong sector of BGPF supports the 20 MWe modular power plant that was commissioned in 1997. Due to the very high concentration of silica found in the waste brine, silica inhibition trials were conducted in Botong prior to the commissioning of the power plant. The silica rich waste brine was injected to wells OP-1RD and OP-2RD. Injection well OP-1RD was utilized during the silica inhibition trials for around two months in late 1995 while well OP-2RD was used in the silica slurry injection tests during the months of November to December 1996, and briefly in April 1997. The injection trials conducted in these wells produced a significant reduction in their injection capacities that prompted PNOC-EDC to program a stimulation treatment for these wells in October 1997 (Malate et al., 1999).

Downhole measurements conducted in these wells revealed several blockages inside the wellbore. Hard silica scales combined with some drilled cuttings were collected from scraper runs that possibly caused these blockages. These hard silica scales may have not only deposited inside the wellbore but may have also deposited behind the liner and into the permeable zones. Hard silica scales were also found to have deposited in the surface injection lines after the silica inhibition trials.

When hard silica scales have to be drilled out inside the liner, it is very likely that the scales have also formed behind the liner. These hard silica deposits behind the liner are difficult to remove mechanically. Pumping high velocity fluid through nozzles at the end of a coiled tubing may loosen the scales around the perforated liners, but this kind of operation was found to be quite expensive.

The problem of treating the solid silica scales behind the liner and the formation damage near the wellbore was then addressed by soaking injection wells OP-1RD and OP-2RD with mud acid prior to the main acid treatment. This option proved to be a better and cheaper alternative than using coiled tubing.

Wellbore soaking has been successfully applied to remove damage in oil and gas wells (Williams et al., 1979). The damage (paraffin, asphaltene, scale and other damage) is effectively removed by soaking the wellbore with mud acid, aromatic solvents or other chemicals depending on the type of damage. Dissolution tests of the silica scales initially conducted in the field showed increasing silica solubility with time and increased temperature. Results of the solubility tests using regular mud acid (10%HCl-5%HF) after three hours is presented in Table 7 below. The results obtained reinforce the application of wellbore soaking in the acid job design of wells OP-1RD and OP-2RD.

Table 7:   Silica solubility after 3 hours (Malate et al., 1999).

Acid System	Temperature	%Solubility
15%HCl	30°C	0
	80°C	0
10%HCl+5%HF	30°C	~40
	80°C	~97

The acid job design for the two injection wells maintained a dosing rate of 75 gallons per foot of targeted payzone using regular mud acid (10%HCl-5%HF). The main acid is preceded by a preflush mixture of 10%HCl at a dosing rate of 50 gallons per linear foot of targeted payzone. The target payzones were determined from the permeable zones identified from pre-acid completion tests.

The bottom section of well OP-1RD was initially soaked prior to the main acid treatment since this is where the majority of the hard silica scales were collected. All the targeted payzones of well OP-2RD were soaked before the main acid injection. Around 50 bbls of the mainflush acid volume prepared were used in the soaking process for each section. The main acid was pumped through the acid string at very low rates (~2-3 bpm) and the wells were shut-in for around 4 hours by closing the quenching lines. The wells were shut during the soaking period to initiate temperature recovery thereby increasing the rate of silica scale dissolution.

7.5.2 Stimulation results

The two wells registered significant reduction in downhole pressures (~1.5 MPag) during the post-acid injection tests. The drop in downhole pressure during the post-acid completion test signified a decrease in flow resistance due to dissolution of mineral deposits within and around the wellbore.

Considerable improvement in well characteristics were attained after the acid treatment as indicated by the results of the post-acid welltest analysis. The injectivity index increased by around 8 li/s-MPa for OP-1RD and approximately 35 li/s-MPa for OP-2RD. The increase in injectivity together with the reduction in downhole pressure provided a two-fold increase in the calculated injection capacity of both wells. Injection capacity of OP-1RD increased from 30 kg/s to 70 kg/s (133%) while the capacity of OP-2RD similarly increased from 70 kg/s to 137 kg/s (96%). Increased negative skin values were also obtained from both wells indicating that initial skin damage had been removed.

The stimulation results obtained in OP-1RD and OP-2RD were also compared with the result of an acid stimulation job conducted in an injection well in one of the other projects operated by PNOC-EDC. Injection well 5R-7D in the Malitbog sector of the Leyte Geothermal Production Field was also used in one of several silica inhibition trials conducted in the area sometime in 1995. The well also suffered a significant decline in injection capacity after about six months of testing. The permeability of the well is similar to injection well OP-1RD. This well was treated with the same acid mixture used in Botong wells but was not soaked in regular mud acid prior to the main acid injection.

The improvement in injection capacity gained in wells OP-1RD and OP-2RD is greater than the increase in injection capacity in well 5R-7D (See Table 8). Acidizing of well 5R7D resulted in an increase of 22 kg/s (25%) in injection capacity compared with 40 kg/s (133%) and 67 kg/s (96%) for wells OP-1RD and OP-2RD respectively. The results of the acid treatment and comparison with the previous acid job in Leyte are summarized in Tables 8 and 9 respectively.

Table 8: Summary of acid treatment results for OP-1RD and OP-2RD (Malate et al., 1999).

Wellbore Parameters/ Calculated Injection Capacity	OP-1RD		OP-2RD	
	Pre-acid	**Post-acid**	**Pre-acid**	**Post-acid**
Injectivity Index, (li/s/MPa)	19.3	27.2	23.0	57.6
Skin Pressure drop, ΔP (MPag)	-	1.5	-	1.5
Transmissivity kh, (darcy-m)	1.2	1.3	3.5	3.8
Skin, s	-1.4	-2.8	-1.2	-4.8
Injection Capacity, (kg/s)	30	70	70	137

Table 9: Comparison with injection well 5R-7D (Malate et al., 1999).

Well Name (Location)/ Parameter	5R7D (LGPP)	OP-1RD (BGPF)	OP-2RD (BGPF)
Increase in Injection Capacity, kg/s	22	40	67
% increase	25	133	96

PNOC-EDC has also acidized a significant number of production wells since 1993. The majority of these wells were stimulated due to the presence of formation damage, mainly mud, during drilling (Buñing et al., 1995; Malate et al., 1998; Yglopaz et al., 1998). Stimulation results also showed dramatic improvements in the capacities of the treated wells. Table 10 shows some of the wells acidized by PNOC-EDC and their corresponding improvements.

Table 10: Summary of pre and post-acid well test analysis results (after Sarmiento, 2000).

Wellname	Project	Wellhead Potential			Improvement
		Original	Pre-acid	Post-acid	
PN-32D	Palinpinon	2.2 MWe	2.2 MWe	4.1 MWe	86%
110D	Leyte	4.1 MWe	4.1 MWe	12.4 MWe	202%
MG-29D	Leyte	Non-discharging	Non-discharging	7.3 MWe	
MG-27D	Leyte	Non-discharging	Non-discharging	8.9 MWe	
MG-30D	Leyte	4.3 MWe	4.2 MWe	14.7 MWe	>240%
MG-31D	Leyte	Non-discharging	Non-discharging	19.6 MWe	
MG-28D	Leyte	5.9 MWe	5.9 MWe	8.2 MWe	>40%
MG-24D	Leyte	3.8 MWe	3.8 MWe	5.6 MWe	>50%
MG-26D	Leyte	untested	untested	2.4 MWe	
OP-5DA	Bacman	1.5 MWe	1.5 MWe	4.1 MWe	173%
OP-3D	Bacman	2.6 MWe	2.6 MWe	5.5 MWe	110%
PN-33	Palinpinon	Non-commercial	Non-commercial	2.4 MWe	240%
PN-25D	Palinpinon	1.2 MWe	1.2 MWe	2.6 MWe	117%
SK-2D	Mindanao	Non-commercial	Non-commercial	4.3 MWe	430%
SK-4	Mindanao	Non-commercial	Non-commercial	3.5 MWe	350%
APO-1D	Mindanao	3.5 MWe	3.5 MWe	5.1 MWe	160%
TM-1D	Mindanao	2.5 MWe	2.5 MWe	5.7 MWe	320%

8 Fracturing

Fracturing is a well stimulation method in which large conductive fractures are created in the formation around the wellbore, reaching far into the reservoir. Exerting a pressure in the wellbore exceeding the fracture pressure of the formation creates the fractures. This pressure is applied from the surface by high capacity (frac) pumps that inject fracturing fluids at a rate exceeding that, which can be injected in the matrix formation.

When the formation can no longer accept the injected fluids at the high rate, new flow channels are formed. These new flow channels are the fractures. Fractures are then initiated, propagated and held open as long as injection proceeds. As injection is terminated, the fractures tend to close again (Economides and Nolte, 1989).

There are two main reasons for fracturing. The first and primary reason is poor permeability, in which case the well would not be able to produce by radial flow at an economic rate. A conductive fracture provides much more surface area for produced fluid to flow into. This fluid can then be more rapidly produced into the wellbore. The second reason

for fracturing is to overcome the damage that extends to a greater depth that cannot be effectively removed by matrix acidizing.

Two methods are generally used to keep the fracture open and conductive after injection stops. These are:

a. Propping the fracture. Proppant materials are mixed at the surface with viscous fluids that carry and distribute the proppants as a pad slurry, depositing them in the fracture created to hold the fracture open. This method is usually referred to as *hydraulic fracturing*.

b. Acid etching along the fracture wall. Acid is injected into the fracture following the inert pad fluid that creates the fracture. Acid etches the fracture walls to create irregular surfaces that keep the fracture partially open and conductive after injection ceases and the overburden pressure causes closure. This method is generally known as *acid fracturing*.

It is generally believed that fracturing treatment results in a single fracture oriented more or less in the vertical plane of the wellbore. This fracture propagates outward symmetrically in opposite directions from the wellbore. It is also believed that, in cases where a fracture job is carried out in a shallow formation, a horizontal (pancake) fracture may develop.

PNOC-EDC has also tested the applicability of hydraulic fracturing in three wells in Leyte. These were tight injection wells with poor permeability. The fracturing operation also involved injecting viscous frac fluid to induce fracturing of the formation and the use of proppants to maintain the open fractures. The stimulation procedure gave mixed results where the first two wells attained commercial injection capacity that made the wells available to the injection system. The third injection well did not gain additional capacity after fracturing. This was evaluated to have been due to the "sealing fault" boundary intersected by the well that was not accounted for in the fracturing design.

9 Gas / air lifting

The majority of the wells drilled by PNOC-EDC are situated at high elevation (800 to 1,000 meters a.m.s.l) where water levels stand from around 400 to 1,000 meters from the surface. These wells usually have difficulty initiating discharge with the exception of wells that tap the vapor dominated zones of the reservoir. The low temperatures at the upper section of the wells aggravate the problem since the reservoir fluid will require more energy to overcome the heat losses to the surrounding formation. PNOC-EDC has initially adopted air compression or two-phase injection to initiate discharge of these wells. More recently, the company employed other well intervention operation in the form of gas /air lifting to unload the cold column of water.

Sta Ana (1985) derived the empirical criteria used by PNOC-EDC to establish the viability of a well to discharge by air compression. Wells failing this criteria are then subjected to two-phase stimulation whenever possible. Where two-phase injection is not possible, gas (nitrogen) lifting remains the only available option for the well that has no capability to self-discharge.

In a geothermal well, nitrogen gas lifting mainly aims to reduce the wellbore pressure to saturation. This can be achieved when the gas lightens the wellbore fluid upon mixing from the injection point and up the hole, creating a lifting effect on the cold liquid column. The wellbore pressure at the feedzone drops, which in turn induces the flow of reservoir fluid into the wellbore and up the surface (Buñing et al., 1998).

In 1998, PNOC-EDC commissioned a high-pressure high-volume air compressor package (1,500 psig at 1350 scfm) for air lifting applications. The unit replaced the 90,000 scfm

nitrogen gas converter earlier used in most of the company's gas lifting activities. For practical purposes, compressed air approximates the action of nitrogen gas in lifting geothermal fluids. However, its corrosive effect on the carbon steel coiled tubing has been significant enough to warrant additional safety precautions, such as: (1) flushing the tubing with corrosion inhibitor solution before and after each job; (2) frequent cutting of tubing sections observed to have developed severe corrosion pits; and (3) minimizing of air pumping time whenever possible.

The company largely gained maximum benefits from the technique in two ways, namely: 1) proving the discharge potential of the wells and subsequently the commercial viability of the exploration projects where all the wells did not have self-discharge capability; and 2) enabling discharge testing of the wells immediately after drilling or workover without the normal period given to the well for heat-up, thus beating contractual deadlines for steam availability in developed projects.

10 Chemical inhibition

PNOC-EDC has also adopted chemical inhibition in treating the discharge fluid and the waste brine for mineral deposition. The treatment methods include the use of anti-scalant for calcite deposition in production wells and silica deposition in injection lines. Calcite inhibition is conducted by injecting an aqueous solution of an acrylate polymer through a capillary tubing system at depths below the flashpoint (Buñing et al., 2000). Polymaleic solutions are used as inhibitors for silica deposition. Injection of acid through pH modification as an alternative to the costly silica inhibitors has also been recently tested with success. On the other hand, pH modification through injection of NaOH is employed to address the corrosion problems in condensate lines.

11 Conclusion

The current well intervention techniques presently employed by PNOC-EDC have been considered effective and consistent with the requirements of sustaining long-term operation of its geothermal fields. Experiences obtained from these intervention procedures show that the chance of success is generally increased with a correct and appropriate engineering approach to any well problem.

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