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MANAGEMENT OF GEOTHERMAL RESOURCES IN THE PHILIPPINES

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ABSTRACT

Different practices and application of recent advances in technology have contributed enormously to management of geothermal resources in the Philippines. During the last 30 years, a significant stride had been achieved to enable the expansion and optimization of field capacities resulting in an increased contribution to the country's power mix by up to 24 %. Crucial to this is the geothermal industry's ability to minimize risk in the existing geothermal fields which are needed to sustain their long term production for at least 25 years. The formulation of development and management strategies lead to a better operation and a more efficient use of geothermal resources, which have been continuously evolving in response to the changing thermodynamic and chemical properties of the reservoir fluids. The different aspects of these management strategies as well as the other practices are reviewed in this paper.

1. INTRODUCTION

Electrical utilization of geothermal energy in the Philippines was first demonstrated in Tiwi, Albay in 1967 by tapping steam from a shallow gradient hole to turn a laboratory turbo-generator that lit up an electric bulb. Since then, geothermal development took on momentum with the installation of the country's first commercial pilot plant in Tongonan, Leyte with a capacity of 3 MW. In 1980, a total of 446 MW was installed putting the Philippines second in rank after the United States in terms of installed geothermal plant capacity. The Philippines remains the second largest producer of geothermal energy in the world with a total installed capacity of 2,027 MW up to the present (Figure 1). Sarmiento (2007) showed that since 1990, the Philippines ranks first in building power plants on an average annual basis. Disregarding the years where no power plants were built, the Philippines was building power plants from 1977-1984 at a rate of 127 MW per year and from

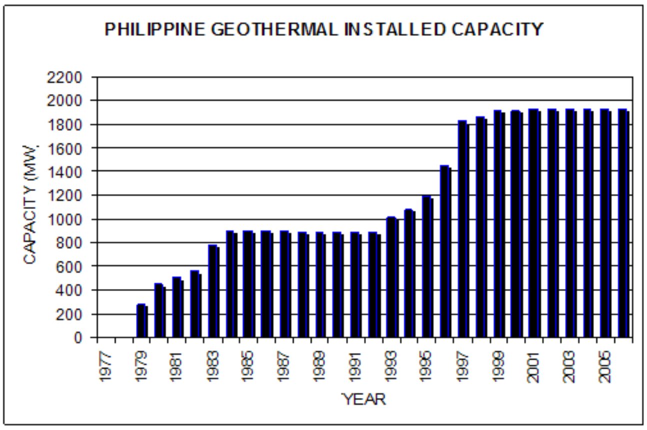

FIGURE 1: A graph of the installed geothermal capacity in the Philippines

1993-1999 at 170 MW per year. A total of 658 wells were drilled in the country in its quest for maximum development of geothermal resources (Figure 2). This unparalleled growth of geothermal development in the Philippines has been attributed to many factors. First, to the impetus placed by the government in searching for and developing indigenous sources of energy to reduce the country's dependence on imported oil. Second, was the strategic location of the Philippine archipelago, which spans a section of the 40,000 km Pacific Ring of Fire; a zone of frequent earthquakes and volcanic eruptions along the basin of the Pacific Ocean. Third, was the bold and aggressive strategy adopted by the government in putting more risk capital by fast-tracking the completion of all geothermal fields. Fourth, but not least, was the sustained effort to prudently manage all of the operating fields in order to maintain the generation level. Field management is crucial because in the other direction lies failure. With accumulated years of experience, continuing modification and adjustments on the various management strategies have been adopted to conform to what the respective reservoir requires in terms of changing thermodynamic and chemical properties. This paper addresses the various techniques and practices applied in the Philippines in the management of geothermal resources, many of which were presented on several conferences and lectures (Sarmiento, 1993; Sarmiento, 2000; Sarmiento, 2007).

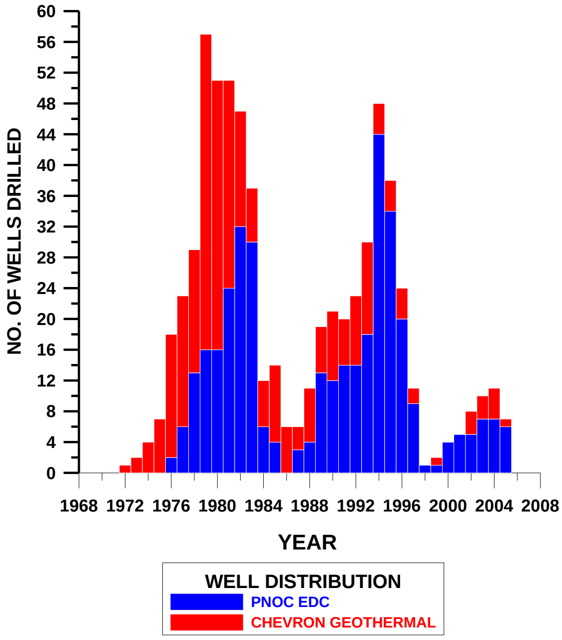

FIGURE 2: Annual number of geothermal wells drilled in the Philippines

2. EXPLORATION AND RESOURCE DEVELOPMENT

The first act in resource management can be traced once the size of a power plant is committed in a geothermal field. The current practice of being conservative from the early stage of development in sizing up the resource and its corresponding generation level to within the allowable risk can already be considered an act of resource management. However before reaching a decision on what size of plant and what type of plant conforms to the resource; geological, geochemical and geophysical surveys need to be undertaken. These studies have been the subject of presentations elsewhere in this workshop and do not need further discussion. In delineating the resource area and boundaries, all the three disciplines play a large role and a result from one discipline is not set aside in favour of the other. It is a rule that every geophysical anomaly needs a geological explanation. To come up with a favourable decision in drilling a prospective area, the following parameters need to be present:

- suitable temperature based on chemical geothermometers
- large size anomaly based on MT/TEM or other resistivity surveys
- benign chemistry of reservoir fluids; trace of acid fluids acceptable
- proximity to load centre and transmission grids
- exceptions are those that may be in conflict with government laws, ancestral domain or indigenous acts and other environmental restrictions

The Philippines had already explored 22 geothermal prospects in the country to date and more areas remain to be explored. Exploration wells are drilled to delineate at least 50-100 MW in three different targets. The confirmation on the existence of a geothermal resource leads the development program in an area to finally commit a certain block of power for generation. In an ideal case, one should commit the field only after the completion of field-wide testing and evaluation to ensure that any development strategy that is to be adopted fits well with the anticipated behaviour of the field.

2.1 Reinjection philosophy

The Philippines pioneered reinjection as a means of disposing its effluents and managing the resource through the recycling of geothermal brine. It is a critical component of every field development. Reinjection strategies in the Philippines are usually based on the following philosophies.

- Dispersal of reinjection fluids
  a) To avoid concentration of reinjection fluids and their possible returns into a particular production sector.
  b) To extend the area of contact between the reinjection fluids and the rock for reheating the fluids before returning into the production sector.
- Deep reinjection
  a) To improve thermal recovery where the temperatures are higher
  b) To minimize the return of the cooler fluids at a shallow depth in the reservoir.
- Peripheral injection
  a) To be as far away as possible from the production sector (2-3 km)
- Gravity Reinjection/Injection Pumping –
  a) To bring down the capital and operating cost of the production facilities
- Cold Injection
  a) To minimize the cost of fluid handling and pipe work especially if the brine flow is minimal
  b) To minimize the problem on silica deposition in the line and the reinjection wells
  c) To utilize wells that are not hooked up to the system because of their long proximity
  d) To be able to adapt to the lower brine temperature of the binary plant

2.2 Production philosophy

The main production strategy in developing a field focuses on maintenance and sustenance of the field capacity during exploitation. Over-exploitation is avoided because all economic considerations on the field development are based on the 25 year lifespan of the power plant.

The following parameters have considerably affected the choice of the production strategy in the Philippine geothermal setting:

2.3 Well flowing and turbine inlet pressure

The well flowing pressure which dictates the final turbine inlet pressure is always based on the optimum flowing pressures that the majority of the wells can support on a long term basis. This is determined by graphically plotting the flows of all wells at different well head pressures and choosing the point where the output is maximized. These are sensitized against other parameters like pipe sizes, the cost of the turbine and the predicted performance of the field. In Tongonan, a power optimization was implemented when it was found out that the wells could operate at 1.o MPa instead of .55 MPa after 10 years. A resulting 50 MW additional capacity was gained without drilling new wells (Sarmiento et. al. (1992).

2.4 Casing configuration

Until very recently, well casing design in the Philippine constitutes only the conventional 9-5/8" as production casing and 13-3/8" as anchor casing. With the availability of the GWELL wellbore simulator (Aunzo, 1990), we had established a comparison of the benefits and the cost of drilling large and conventional holes. The break-even point where a big hole looses its advantage is if the hole can only gain a 30 percent increase in power. On the other hand, wellbore simulation results indicate that as high as a 60 to 80 percent increase in power can be obtained in areas where the wells' output is wellbore controlled - i.e., the output is controlled by the wellbore size. With a known production performance on initial wells in a field, additional wells can be drilled with a large diameter casing when necessary. Figure 4 shows the comparative output of well OK-6 in Palinpinon and well 212 in Tongonan at 9-5/8" and 13-3/8" casings.

2.5 Field enthalpy

The average field enthalpy dictates the number of reinjection wells and size of reinjection system to put up in an area. High enthalpy wells produce a relatively smaller amount of effluent than those low enthalpy wells. For example, in Mt. Apo, the first 3 production wells were drilled near the outflow of the field and thus producing low enthalpy fluids. Although the sector can produce the required capacity of 40 MW for the first unit, the drilling program has to be shifted towards the upflow region to obtain a better well output, reducing the required number of wells and to meet the programmed commissioning of the plant by September 1994. When reinjection returns start affecting the productivity of the wells, drilling M&R wells are directed towards the shallower steam cap to minimize brine returns.

2.6 Fluid chemistry

Cut-off pH from the discharge fluid from the production wells is set at 4.5 during which corrosion effects are monitored. Once the pH of the discharge fluids becomes lower than the cut-off value, the well is cut out of the system and more often becomes non-commercial. More recently, however, it was shown in Palinpinon I, that by inducing reinjection returns into the acidic feeds of these wells (OK-10D and PN-22D), the pH of the overall discharge improves, and the well becomes reusable for commercial production. In other cases acidic wells are left shut until the steam cap develops and the fluids turn neutral.

Reservoir fluids in the Philippines are highly mineralized as temperatures in most geothermal fields are over 300 °C. These minerals reached supersaturation in the brine after the separators after flashing at low pressures, i.e., at 0.6 MPaa. Whenever possible, PNOC-EDC optimizes the separation pressure concerning silica saturation to mitigate scaling. In Bacman I, the wells will be initially operated at 1.0 to 1.2 MPa, even though the turbine inlet pressure is only 0.5 MPa, to maintain a silica saturation index (SI) close to 1.0.

2.7 Topography

When a geothermal resource is located in a mountainous terrain, as is the case in many geothermal fields in the Philippines, road works and pad constructions are usually limited. Production wells are usually lumped in a few numbers of pads, and are drilled directionally to be able to tap the inferred upflow of the resource. Fluid collection and disposal systems of such a development tend to become less complicated, however, as the wells can easily be connected to the steam gathering system since their wellheads will be close to each other.

3. RESERVOIR MANAGEMENT STRATEGIES

Reservoir management is essentially overseeing the operation of the geothermal field aimed at ensuring the sustainability of the plant operation for 25 years or longer. One aspect is reservoir monitoring to track and evaluate changes in reservoir characteristics and to identify threats and solutions on potential problems.

3.1 Output monitoring

Figure 3 shows the comparison of the Palinpinon field capacity based on the power plant estimate and that from bore output measurement using James' method. Through this technique, even the wells which are cycling at the time measurement and while supplying to the power plant were identified like wells PN-17D and PN-14D. The results become more applicable in projecting steam shortfall although it does not answer questions on changes to individual well output.

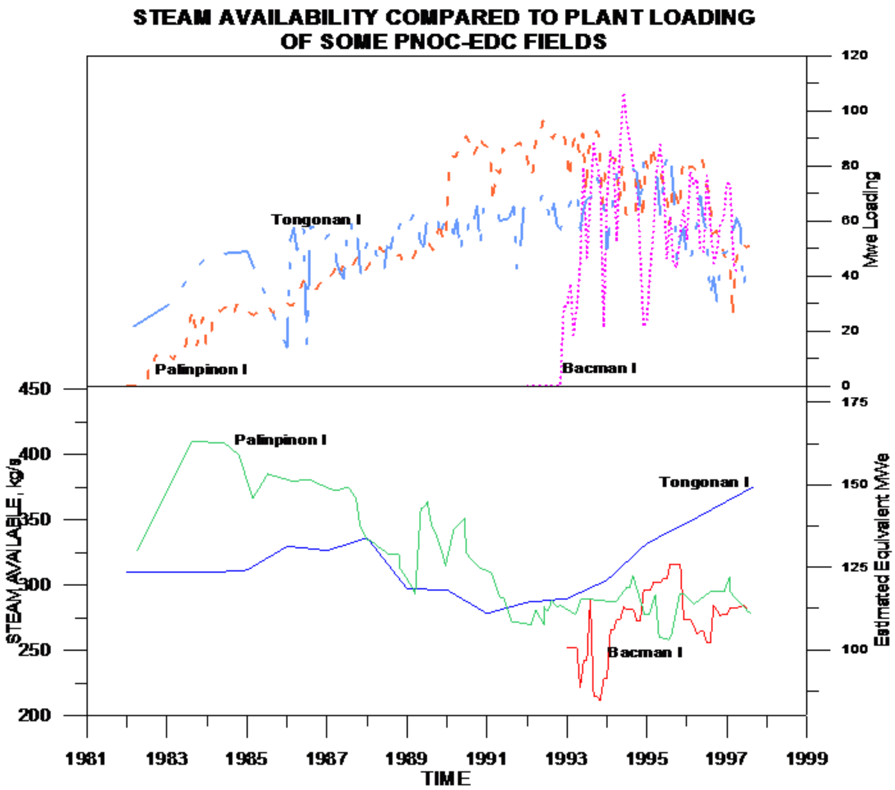

FIGURE 3: Comparative steam availability of steam against power demand (After Sarmiento, 1993)

3.2 Reinjection flow and capacity monitoring

Total reinjection flow and reinjection well capacity measurements are essential in good reservoir management especially in a field where there is a continuous return of reinjection fluids to the production sector. Estimates of the total wastewater flow give an indication on whether the field enthalpy is increasing or declining and therefore the pattern on the behaviour of the production wells. On the other hand, the estimate on the changes in the reinjection wells capacities indicate whether a work-over is necessary to recover lost capacity or drill additional wells to cope with the reinjection load requirement. To continuously monitor injection capacities, chemical tracers, orifice plates and downhole spinners are used alternatively whichever is practical to the system.

3.3 Well work-over

Mineral deposition is an inherent phenomenon in many geothermal fields in the Philippines. Anhydrite blockage occurs in wells where there is a mixing of SO_4 rich fluids with Ca rich fluids from different feed zones during production. On the other hand, silica scaling is a common problem in reinjection wells because the brine being injected is super-saturated with silica. These phenomena reduce the respective productivity and injectivity of the wells that require remedial action.

In the 80's, PNOC-EDC usually cleared the well by plain mechanical work-over or drill-out of the blockage to restore well productivity and capacity (Figure 4). Positive results have been achieved from this technique. Recently, advances in field management and chemical inhibitions and other chemical treatment significantly reduced the frequency of a workover.

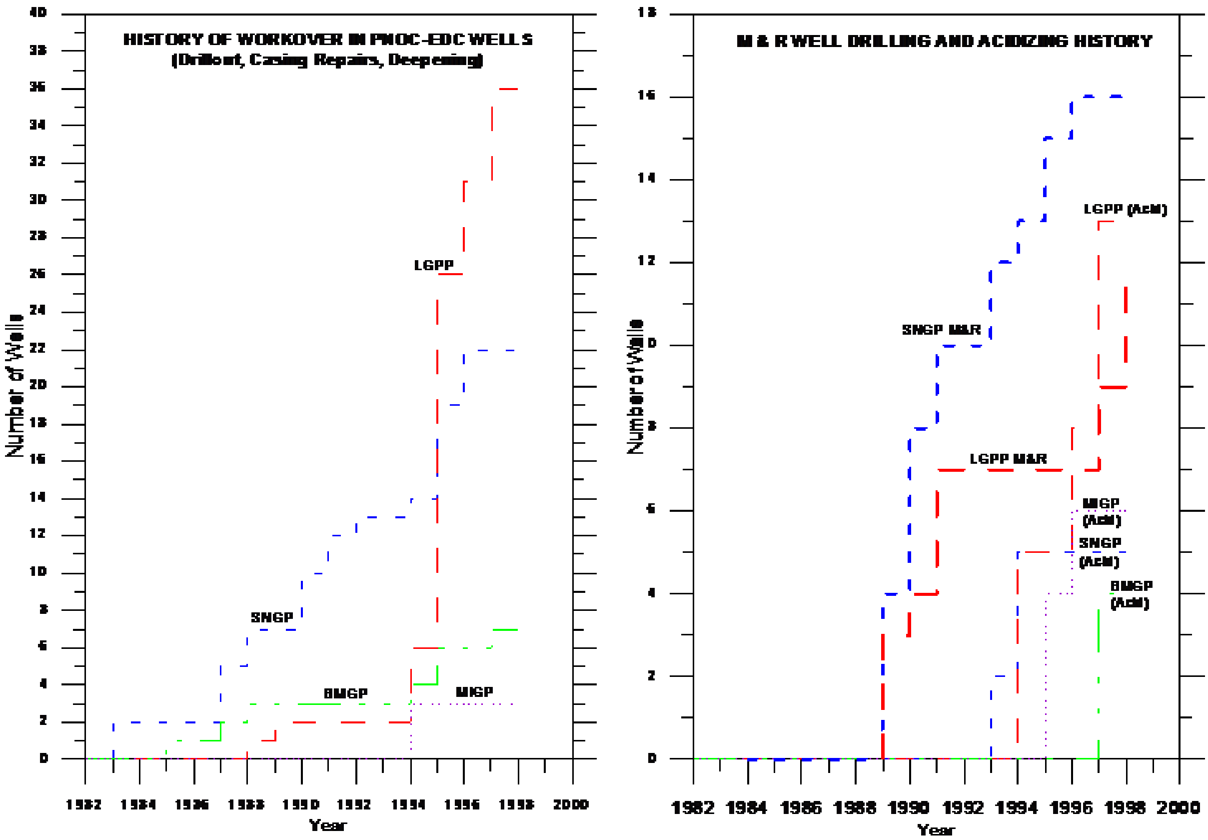

FIGURE 4: Workover and M&R well drilling history in many fields in the Philippines (After Sarmiento, 1993)

3.4 Downhole temperature and pressure measurements

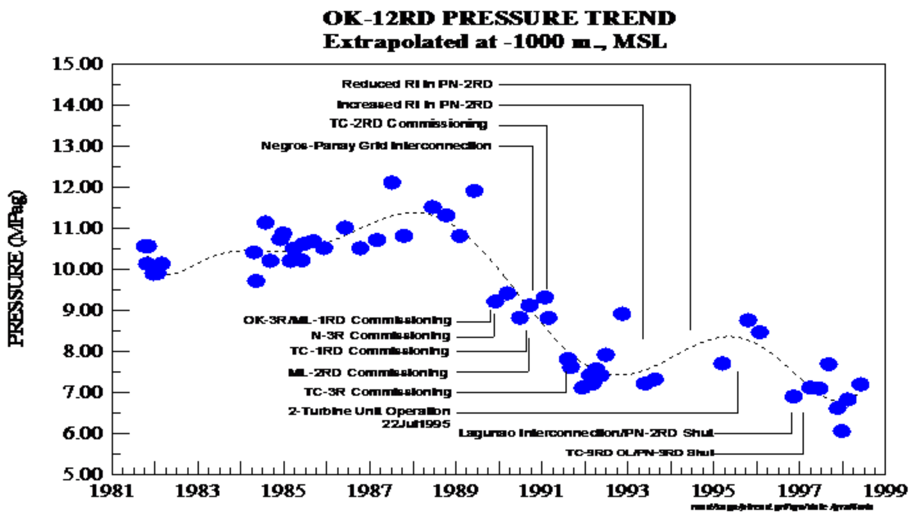

FIGURE 5: Pressure trend measured in Well Ok-12RD in Palinpinon in response to various reinjection and power plant load (After Sarmiento, 1993).

Downhole temperatures and pressures are sensitive to mass withdrawals during exploitation. At saturation conditions, temperatures drop as a result of pressure. This is normal behaviour in a well under production until such a time that boiling conditions exist throughout the field. When fluids remain in a single phase, temperature drops are not supposed to be observed unless cooling takes place as a result of ingress of ground or surface waters and reinjection returns. Increases in temperatures may be caused by a recharge of higher temperature fluids at greater depths. All of these are being monitored to determine whether the field is being depleted or is in a steady state where no changes occur at a particular generation level (Figure 5). Baseline data of downhole measurements are established in all wells before commercial operation to be able to portray all future changes when exploitation begins. Measurements are scheduled once a year per well during production and when significant change in the output of the well occurs.

3.5 Chemical monitoring

It is widely accepted that changes in fluid chemistry comes in advance than changes in physical properties like temperature and pressure. Fluid chemistry monitoring therefore plays a significant role in forewarning potential problems in the reservoir, and in many cases replaces downhole temperature and pressure monitoring if a good understanding and knowledge of field behaviour exists at various operating conditions. Figure 6 demonstrates changes in fluid chemistry of production wells in Palinpinon when changes in the reinjection well utilization are implemented. The fluctuating reservoir Cl is a reflection of the effects of wells being utilized during a particular period.

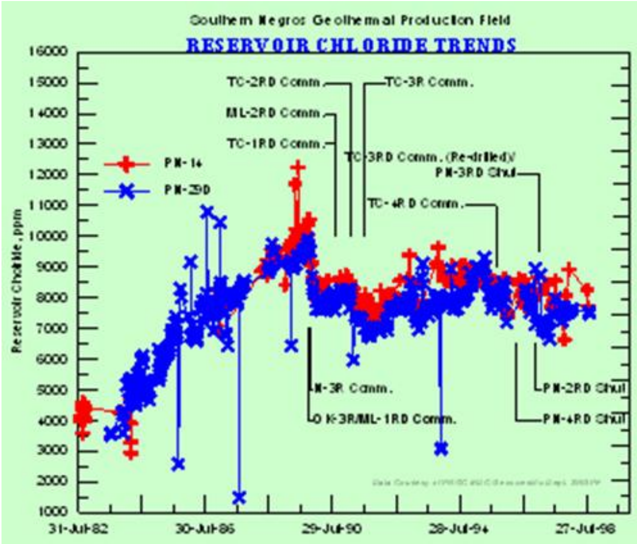

FIGURE 6: Reservoir chloride trend in two production wells in Palinpinon geothermal field reflecting the effects of utilization of the reinjection wells.

3.6 Steam accounting

As a check against excessive use and wastage of steam in the operation of the production facilities, regular steam accounting is also implemented. The operation of the facilities is only allowed a maximum blow-off or bypass of steam to ensure safe operation and to cope up with any surge or increase in load demand.

4. WELL DRILLING

Drilling cost in the Philippines represents approximately 60% of the total cost of the steamfield and about 30% of the total steamfield and power plant cost. It is therefore imperative to prudently manage drilling operations to maintain project costs at desired levels of investment. Since drilling started in the Philippines in the mid '70's, and until 2000, and with a total of 658 wells, several improvements in drilling practices have emerged. These improvements account for better performance in shortening the number of days required to drill a well.

Figure 7 shows the drilling performance in the Philippines during the last 15 years based on the various reports by Talens et al., (1997), Southon (2003), Herras and Jara (2006). These wells were selected to show the marked difference in the drilling performance for the various wells. The red and the blue squares shows that as much as 20 days were involved in non-rotating hours

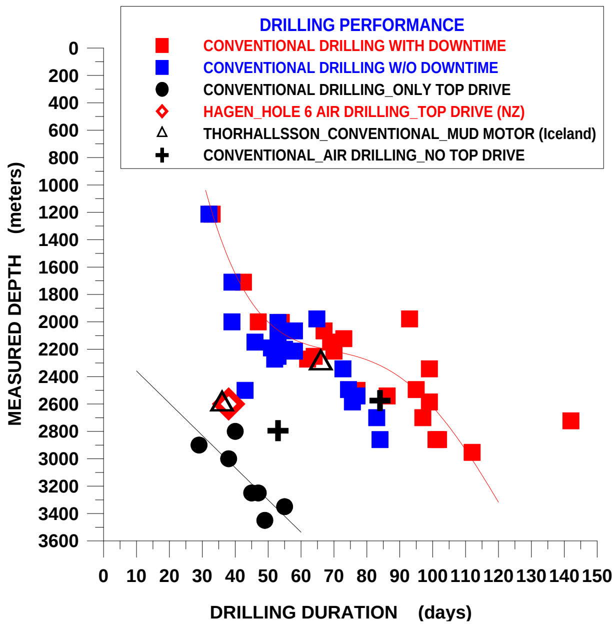

FIGURE 7: Comparative drilling completion on selective wells in the Philippines and those in New Zealand and Iceland (After Sarmiento, 2007)

(downtime) from the performance of a conventional rotary drilling rig using mud as the main drilling fluids. The graph of the total depth vs. drilling duration indicates that there is a significant potential for improvement in achieving faster drilling by mainly reducing the downtime incurred during the actual drilling, which by experience makes up from 15 to 25 %. Furthermore, 10 to 17 % of this downtime could be controlled with better planning and logistical services. The black circles represent what could be considered as drilling record for completing geothermal wells in a span of 26 days for 2800 meters, and less than 60 days for 3400 meter wells, by using a conventional rig equipped with a portable top drive system and steerable MWD tools (Southon, 2003). Other improved drilling practices that involved reducing the non-rotating hours were also implemented which had significantly contributed to the new record. This emerging performance record deviates significantly from the unpredictable performance of past drilling results, with a duration of 60-120 days. The open diamond is a well completed in NZ using air drilling and a top drive to supplement the conventional rig (Hole, 2006). The black crosses represent the performance of a conventional rig in the Philippines without a top drive but with aerated drilling. One of the two wells fits linearly with this well in NZ (Hole, 2006). The two triangles represent two wells drilled in Iceland; one using conventional drilling and the other using mud motor drilling down to TD (Thorhallsson, 2007). The first well that was drilled conventionally fell within the performance of many wells (red and blue squares); the well drilled with the mud motor all the way matches the well drilled with air drilling. It is clearly shown in the plot that the result from a combination of aerated drilling and top drive units adopted from Hole (2006) was not enough to match the drilling rate demonstrated in the Philippines. The objective of using aerated drilling in the Philippines for drilling and completing infill wells has been achieved with a better drilling rate than conventional drilling. To further demonstrate the unpredictable drilling performance in the Philippines, many wells with available information were plotted in Figure 11. The following techniques and equipment have been incorporated from conventional drilling practices that resulted in better drilling performance.

4.1 Under balanced air drilling

Reservoir depletion due to continuous production has resulted in significant pressure drawdown and expansion of the two-phase zone in maturing fields in the Philippines. During the drilling of infill wells, the mud hydrostatic pressure exceeds the reservoir pressure, especially at the top zone where steam is easily condensed and collapsed. This transition in the fluid properties of the reservoir causes drilling fluids to be lost to the formation, especially when penetrating the highly fractured andesitic lavas and pyroclastics in the reservoir. This condition has added complexities to the inherently problematic drilling operations in the Philippines. Jumawan et al (2006) and Herras and Jara (2006) described the performance of conventional drilling mud and aerated fluids while drilling infill wells at the centre of the under-pressured reservoir of Tongonan. Two wells were drilled with the same target in the same sector where there is significant pressure drawdown; first, with conventional drilling mud fluids and the second well with aerated mud/water at underbalanced drilling conditions. The objectives of the two wells were to drill up to 2,900 meters to tap the high temperature fluids at depth. The casing shoe had to be set from 1,600 to 1,900 meters to avoid producing from the depleted top zone. All losses were required to be plugged. Unrecoverable losses and blind drilling led to the premature completion of the first well while drilling with conventional mud fluids. Mud fluids and cuttings migrated swiftly to adjacent wells causing surges to water levels in separators, and a subsequent increase in total suspended solids in steam. The turbines required temporary shutdown until remedial action was taken to reduce the TSS. Some wells collapsed due to substantial cooling, and drilling could not progress until the well was prematurely TD'ed. The major impact of these problems was the reduction in total output of the field and forced acidizing of production wells that had communicated and had been damaged by mud while drilling. Learning from this experience, subsequent drilling in the same sector was conducted with aerated drilling, and full circulation returns were recovered by adjusting the air-water and air mud ratios. Steam influx and well kicks from the top zones were allowed but at conditions where temperatures would not go beyond the limitation of the rubber O-rings of the BOP stack (Jumawan et al., 2006). Good hole cleaning due to the maintenance of full circulation led to the completion of these wells at much deeper levels than when they were drilled with conventional mud systems. One well was completed to 2,900 meters with air drilling applied at the production casing interval only, and mud as the drilling fluids from the 95/ 8" shoe to the bottom hole.

5. STIMULATION METHODS

Stimulation procedures to enhance reservoir permeability are conducted immediately after well drilling completion or subsequently after the well recovery. A successful stimulation job replaces or reduces the number of wells to be drilled, with additional output or capacities gained equivalent to 50 % or 100 % in some cases. It may consist of hydrofracturing, thermal fracturing and acidizing. Hydrofracturing and thermal fracturing create or enlarge fractures that connect with pre-existing fractures within or farther away from the wellbore. Acidizing dissolves the mud that blocks the sandface fractures. Wells also require some stimulation to initiate flow to the surface. These methods involve air compression, gas lift, and two-phase stimulation by boiler or by hook-up from production wells. The availability of the coil tubing unit (CTU) and rig allows the use of nitrogen gas or air to stimulate even the most reluctant wells through the lifting of the cold fluid column to the surface, until the well is emptied and the well kicks by itself. This method is also used to clear the well with mud that settled at the bottom including those that are blocking the permeable zones.

5.1 Hydrofracturing

Hydrofracturing usually involves injecting water at high wellhead pumping pressures, and in some cases entail the use of proppants to wedge the fractures propagated during the operation. Hydrofracturing was conducted during the completion test after high WHP was measured while pumping at minimal flow; a condition suggesting that the well is tight and lacks permeability. The operation consisted of injecting water at a maximum pump rate of 30 l/s for 24 hours until the WHP turned into a vacuum condition. A well is at vacuum condition when it is sucking more fluids than the pump can deliver. The final injectivity index of the well after the *hydrofrac* was 25 l/s-MPag at vacuum condition against 45 l/s-MPag with a positive WHP before the *hydrofrac*. Moreover, a pressure difference of >5 MPa was measured before and during the *hydrofrac* operation, suggesting the opening and enlargement of fractures. The well sustained a commercial output by using the CTU for a gas lift operation.

5.2 Acidizing

Acidizing consists of pumping HCl and HF mixtures to treat the formation of mud damage resulting from drilling operations. Because of the expense involved, this method is usually delayed during the well recovery as an ultimate solution to enhance well output. However, in some cases where the urgency for steam supply requires immediate acid treatment, then it becomes part of the drilling program (Yglopaz et al., 2000).

Since 1993, acid treatment has been widely used in the Philippines to enhance production and injection capacities of geothermal wells. Sarmiento (1993) first showed that the mechanical workover or clearing of scales in reinjection wells should not be confined only within the wellbore, and must extend beyond the sandface to recover lost injection capacity. This finding led to the trial and successful acidizing jobs in Palinpinon involving one production well (PN32D) that was damaged by mud during drilling, and one reinjection well (PN2RD) that had suffered a declining injection capacity. To date, the success of this stimulation method is repeated in the Philippines and around the world on many wells that are suffering from mud damage and mineral deposition. Buning et al., (1995) updated the acidizing results from 1993 to 1995 and reported a significant improvement in the capacities of 9 out of ten wells initially acidized in the Philippines. Other results are reported in Malate et al., (1997), Yglopaz et al., (2000) and Sarmiento (2000). Results of acidizing treatment jobs in the Philippines since the trials in the first two wells gave a minimum 29 % and a maximum 911 % increase in output/injection capacities.

One of the most significant advances in the application of acidizing for well stimulation in the Philippines is the development of a method that predicts the most likely improvement of a well if it undergoes acid treatment. The minimum gain in flow that could be induced by acidizing can be estimated by multiplying the injectivity index of the well and the skin pressure obtained from the difference between the static pressure at reference level and the projected pressure at zero pumping of the injectivity line. This allows for an assessment on whether the acidizing meets a financial hurdle rate and is used in a candidate selection.

6. CALCITE AND SILICA SCALING INHIBITION

As discussed above, well workovers were normally conducted on production and reinjection wells affected by deposition. The Calcite scales constrict the flows of geothermal fluids and cause significant decline in well output. Silica scales also clogged the wellbore and the formation until the well could no longer accept injected water. Mechanical clearing using the rig is frequently done, in some cases every 6 -8 months to restore well output. This technique while effective poses some risks on the life and integrity of the casing as frequent passing of bits and drill pipes inside the hole might cause damage and get stuck on operation. Hence, the use of a chemical inhibitor in preventing the recurrence of calcite blockage deposition inside the wellbore was considered. To date, a calcite inhibition system is a standard installation in wells with a calcite scaling problem. The calcite inhibition system basically consists of a surface injection facility for the mixing and injection of chemical solutions and a downhole injection facility to allow injection of chemical solutions inside the wellbore of a producing well below the flash point depth. Based on initial results, the decline rate in both wells with an installed calcite inhibition system has been reduced significantly from an average of 4.0 kg/s-month to less than 0.5 kg/s-month in terms of total mass flow. Recent experience on silica inhibitors (Geoguard} indicate that the frequency of well workover and acidizing jobs on reinjection wells by at least 4 times is attainable .

7. OTHER WELL INTERVENTION TECHNIQUES

To keep up with the ever increasing phase of sustaining production that is constrained by aging wells, deposition, casing damage, cooling temperatures and the increasing depth of water levels, several other well intervention techniques are applied in the Philippines vis-à-vis:

- Casing perforation - to open up a cased off steam cap at shallower levels in the reservoir
- Air/Gas lifting - to accelerate well cut-in to the system without waiting for the natural temperature recovery, it is also a good method of allowing those wells that are under-pressured and would not flow by itself
- Zone plugging – to isolate acid zones and feed zones that affect the commercial discharge of the wells

8. CONCLUSIONS

The management of geothermal resources in the Philippines has evolved into what is today a more predictable discipline as a result of cumulative experience from many years of production of different types of geothermal systems. With thorough monitoring and understanding of the issues affecting the performance of production fields, measures and improvement on existing management practices further reduce the risk faced by steamfield developers in sustaining the long term production of the field. Improvement in technology and practices has made contemporary drilling responsive to maturing geothermal fields especially the use of air drilling in dealing with under-pressured reservoirs. The combination of the use of a top drive unit, mud motors and durable bits enable drilling to be completed in less than 30 days from what is usually a 60 day drilling period. The use of stimulation methods to prop up the capacities of production and injection wells further improve the economics of this indigenous source since a significant reduction in the total number of wells drilled in a project is achieved. Calcite and silica deposition are no longer an operational problem because of the availability of chemical inhibitors that retard if not eliminate their formation in the wells and the pipeline.

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