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Tiwi Geothermal Field, Philippines: 30 Years of Commercial Operation

Anthony J. Menzies, Larry B. Villaseñor and Eugene G. Sunio

Chevron Geothermal Philippines Holdings, Inc, 14th Floor, 6750 Building, Ayala Avenue, Makati City, Philippines

amenzies@chevron.com

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ABSTRACT

The Service Contract for the exploration and development of the Tiwi geothermal resource was executed in 1971 between Chevron Geothermal Philippines Holdings, Inc (CGPHI) and the National Power Corporation of the Philippines (NPC). The deep discovery well, Naglagbong-1, was completed in June 1972 and demonstrated the commercial viability of the resource. By May 1979, 45 wells had been drilled and the first 55MWe turbine-generator unit had started commercial operation and in April 1982, the installed capacity reached 330MWe. This was a very aggressive development schedule due to the Philippines' heavy dependence on imported oil and the oil price shocks of the 1970's. In 2004-05, four of the units were rehabilitated and the base installed capacity was re-rated to 234MWe, with the retirement of Unit 4 in 2000 and the designation of Unit 3 as a stand-by unit in 2005.

Since the start of commercial operation, gross generation at Tiwi has averaged 157MWe and 40.6TWe-hrs of electricity has been provided to the Luzon grid, saving the Philippines from importing 80.6 million barrels of oil (or equivalent fuel). Generation in recent years has been affected by steam supply limitations, power plant availability and the start of the Wholesale Electricity Spot Market (WESM) which initially resulted in the units being used more as "load following" rather than "base load" plants, although this situation did improve in 2008.

Management of the Tiwi resource over the past 30 years has been a challenge due to various resource related issues, including: meteoric water influx, injection breakthrough, reservoir pressure decline, non-condensable gas concentrations, enthalpy changes and production of corrosive fluids (both sulfuric and hydrochloric acids). These difficulties have been overcome or managed by instituting a number of technical and operational changes. In 2008 the decline in steam supply was minimal, suggesting that the present capacity of ≈200MWe equivalent (based on design consumption of 2.25 kg/s steam per MWe) is possibly sustainable, based on the existing reservoir production/injection strategy. Two new production wells were drilled in late 2008 and early indications are that these wells will assist in maintaining production at the present overall capacity and may also suggest the existence of additional reserves that could increase or extend the capacity in future years, if considered economically viable.

1. INTRODUCTION

The Tiwi Geothermal Field is located on the northeast flank of Mt. Malinao in Albay Province, Philippines, approximately 350km southeast of Manila (Figure 1). Commercial operation began on May 15, 1979, with start-up of the first National Power Corporation (NPC) 55MWe unit and over the next three years, the installed capacity was increased to 330MWe. This was a very aggressive development schedule, dictated by the need of the Philippine Government to reduce dependence on imported oil at a time when oil prices were rising significantly (Alcaraz, et al., 1989). The field has now provided steam to the NPC power plants for 30 years and in spite of many challenges and difficulties, gross generation has averaged 157MWe and a total of 40.6TW.hrs of electricity has been provided to the national grid, saving the Philippines from importing 80.6 million barrels of oil (or equivalent fuel).

During 2008, NPC's power plant assets at both Tiwi and Mak-Ban were privatized and the winning bidder was Aboitiz Power Renewables, Inc (APRI). The formal turnover of the power plants to APRI occurred on May 25, 2009 and Chevron Geothermal Philippines Holdings, Inc (CGPHI) looks forward to partnering with APRI to ensure that Tiwi continues to be a reliable producer of electrical power for the Philippines for many more years to come.

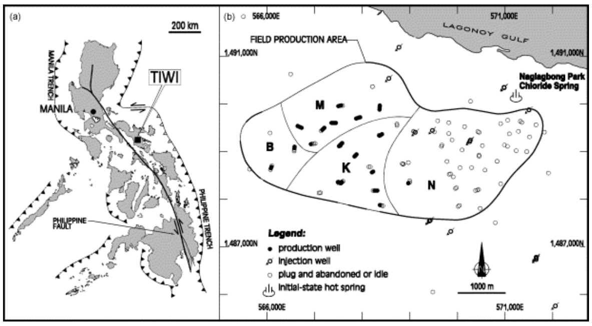

Figure 1: Location of the Tiwi Geothermal Field
(N=Naglagbong; K=Kapipihan; B=Bariis; M=Matalibong)

2. CONCEPTUAL MODEL

Figure 1 shows the layout of the Tiwi field, including the known productive area of 12 square km and the four geographic sectors that the field is divided into: Naglagbong (Nag), Kapipihan (Kap), Matalibong (Mat) and Bariis (Bar).

The initial state conceptual model of the field is summarized in Figure 2 (Sunio, et al., 2004).

There are three upflow zones (Bar, South Kap and Nag) located within the Tiwi field and the heat sources are thought to be small dacitic to andesitic domes located south of the Kap and Bar sectors, as well as a broader heat source beneath Mt. Malinao. The upflows are all neutral-chloride brines, with source temperatures ranging from 280 to 315°C (Na/KCa-Mg geothermometer), reservoir chloride concentrations of between 4,000 to 5,200ppm and NCG content in produced steam of 2.0 to 2.5 wt.% (Molling et al., 2001a Part II). Acid-sulfate fluids are also present on the flank of Mt. Malinao to the south and southwest of the field and this fluid appears to enter the reservoir through faults.

The cap rock that overlies the productive reservoir is associated with argillic alteration and dominated by smectite clay. It is thinnest in the northeast of the Nag sector, where the reservoir top is shallowest (Figure 3). The reservoir top is also shallow in the North Mat, South Kap and Bar areas and deepens in the central part of the field between the Kagumihan and Tiwi faults.

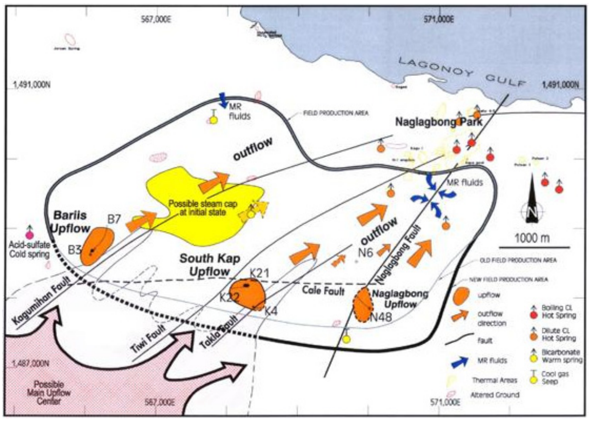

Figure 2: Initial State Conceptual Model of Tiwi

The reservoir basement has only been encountered in the Nag sector at -1,500m msl (Gambill and Beraquit, 1993) and is associated with weakly metamorphosed sedimentary rocks. In the west, the basement has not been encountered, even though wells have been drilled to −2,500m msl.

The most important structures in the Tiwi field with regard to fluid flow are the Kagumihan and Tiwi faults (Figure 2) and possibly the Naglagbong fault. Flow occurs along the strike of these SW-NE trending faults, but they act as semi-permeable barriers to flow across strike. Hence, they separate the Bar and South Kap / Nag upflows and also divide the reservoir into two or three "compartments".

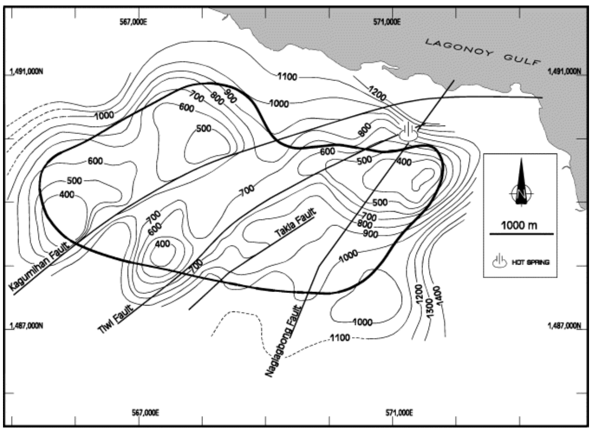

Figure 3: Reservoir Top and Major Structures in the Tiwi Geothermal Field (contours in m bsl – below sea level)

The reservoir was initially an over-pressured (Strobel, 1982) and liquid dominated system (Figure 4), with an average resource temperature of ≈290°C (Sunio, et al., 2004). A shallow steam zone was present in the vicinity of Nag Park, (Figure 4) that was formed by leakage through the caprock and subsequently expanded due to boiling associated with pressure decline. An extensive steam zone was also encountered in the west (Figure 2) that was probably formed by or expanded due to pressure drawdown associated with initial production from the Nag wells.

3. EXPLORATION AND DEVELOPMENT HISTORY

From 1964 to 1968, the Philippine Commission on Volcanology (COMVOL); predecessor to the Philippine Institute of Volcanology and Seismology (PHIVOLCS) evaluated the geothermal potential of the Tiwi field (Gambill and Beraquit, 1993). Their activities included geologic mapping, geophysical surveys and drilling of seven temperature gradient holes; the last of which (COMVOL No. 7) produced steam that was used on April 12, 1967 to run a 2.5kWe demonstration plant. This was the first use of geothermal steam for power generation in the Philippines.

In 1970, NPC was given the mandate to develop the Tiwi Geothermal Field for electricity generation under PD 739. NPC then signed a Service Contract with Union Oil Company of California (now Chevron Corporation) on September 10, 1971 to explore and develop the Tiwi resource to provide steam to power plants to be constructed by NPC.

Philippine Geothermal, Inc. (now CGPHI) conducted further assessment of the prospect, culminating in the drilling of Naglagbong-1 (Nag-1), located near COMVOL No. 7, which was completed on June 4, 1972 to 1,764m. The well encountered a 270ºC liquid-dominated, neutral chloride resource, with low NCG content and sustained steam flow equivalent to ≈3MWe.

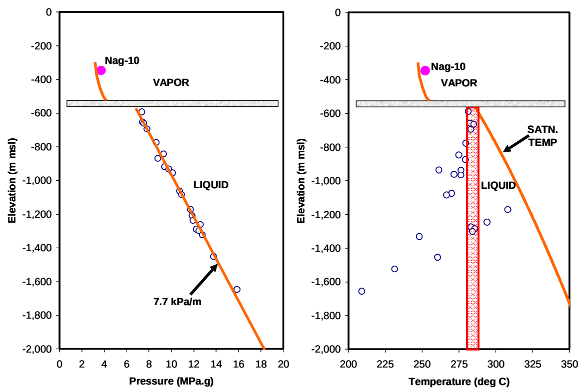

Figure 4: Initial Pressures and Temperatures in Naglagbong Sector Wells (after Strobel, 1982)

Further drilling was carried out to delineate the resource and with the oil shock in 1973 combined with the Philippines heavy dependence on imported oil, the development of Tiwi was accelerated. NPC committed to the first 110MW (2 x 55MW units; Plant A) in 1974 after drilling and testing of the first four wells. By 1976, 18 wells had been completed and NPC committed to a further 110MW (2 x 55MW units; Plant B) development and in 1979, after completing 45 wells, NPC committed to the third 110MW (2 x 55MW units; Plant C). However, it was recognized that the reserves had not been fully proven (Barker, et al., 1990) and it would be necessary to drill future wells further to the west, in the higher elevation areas of Kap and Mat, to expand the resource area. This would require multi-well pads and deviated wells.

The power plants started commercial operation between May 15, 1979 (Unit 1) and April 25, 1982 (Unit 6). By the time Unit 6 started commercial production, 87 wells had been drilled in the field, mainly in the Nag and Kap sectors, and the total steam available was 1,066kg/s; 25% more than required for full load (Barker, et al., 1990).

In 2001, Unit 4 was de-commissioned and in 2004-05 Units 1 and 2 (Plant A) were rehabilitated, with increased capacities of 60MWe each while the capacities of Units 5 and 6 (Plant C) were increased to 57MWe each. This gave a baseload capacity of 234MWe, with Unit 3 designated as a stand-by plant.

There have now been 156 wells drilled in the Tiwi contract area; 37 are presently used for production, including two new wells drilled in late-2008 (Bar-11 and Kap-35), 12 are used for hot brine injection, 8 are cold brine or condensate injection wells and 6 were drilled to investigate other potential prospects. The remaining wells are mainly located in the Nag area and are inactive, although there are also an increasing number of inactive wells located in the Kap-Mat-Bar area.

4. GENERATION, PRODUCTION AND BRINE DISPOSAL

Figure 5 shows generation performance from start-up in 1979 to the end of 2008 and steam production from the eastern (Nag) and western (Kap-Mat-Bar) areas of the field.

The history can be divided into the following time intervals, with the major issues being:

1979–1984: Initial start-up of the power plants, with production mainly from the Nag area, reaching peak generation of 290MWe.

1985–1987: Decline in generation to 170MWe due to the impact of meteoric recharge (MR) in the Nag area.

1988–1995: Recovery in generation to 270MWe due to continued drilling in the Kap, Mat and Bar areas and improvements to surface facilities to optimize steam usage.

1996–2004: Low generation and steam production due to decline in base steam supply, lack of make-up well drilling, low steam efficiency due to deterioration of the power plants and plant shut-downs due to typhoon damage and rehabilitation activities.

2005–present: Improvement in steam efficiency as the rehabilitated plants came back on-line, dispatch issues with the Wholesale Electricity Spot Market (WESM) that limited overall generation, and steam supply limitations.

Note that the steam production (Figure 5) does not necessarily reflect actual steam available when generation is limited by power plant availability or dispatch issues (WESM).

Steam production from the Nag area peaked in 1982 at 660kg/s (Figure 5) but then declined and there has been virtually no production from the Nag area since the mid-1990's, except Nag-28 which stopped flowing in 2000 and was re-flowed in 2007. In the Kap-Mat-Bar areas of the field, the first wells were drilled in 1979 and since 1983, all production wells have been drilled in these areas. When Nag production peaked in 1982, 35% of the steam was already coming from these areas; particularly from Kap. This increased to over 50% by 1984 and to 100% from the mid-1990's. The reasons for this shift in production are discussed in more detail in Section 5.0.

Present steam availability is estimated to be 450kg/s from the 37 production wells, including Bar-11 and Kap-35 (Figure 6). This is equivalent to ≈200MWe, based on the design steam requirement of 2.25kg/s/MWe for the rehabilitated power plants with their mechanical gas extraction systems operating. The discharge characteristics of the wells vary widely (Figure 6) from liquid dominated producers, with enthalpies as low as 1,050kJ/kg, to superheated steam wells with up to 35°C of superheat.

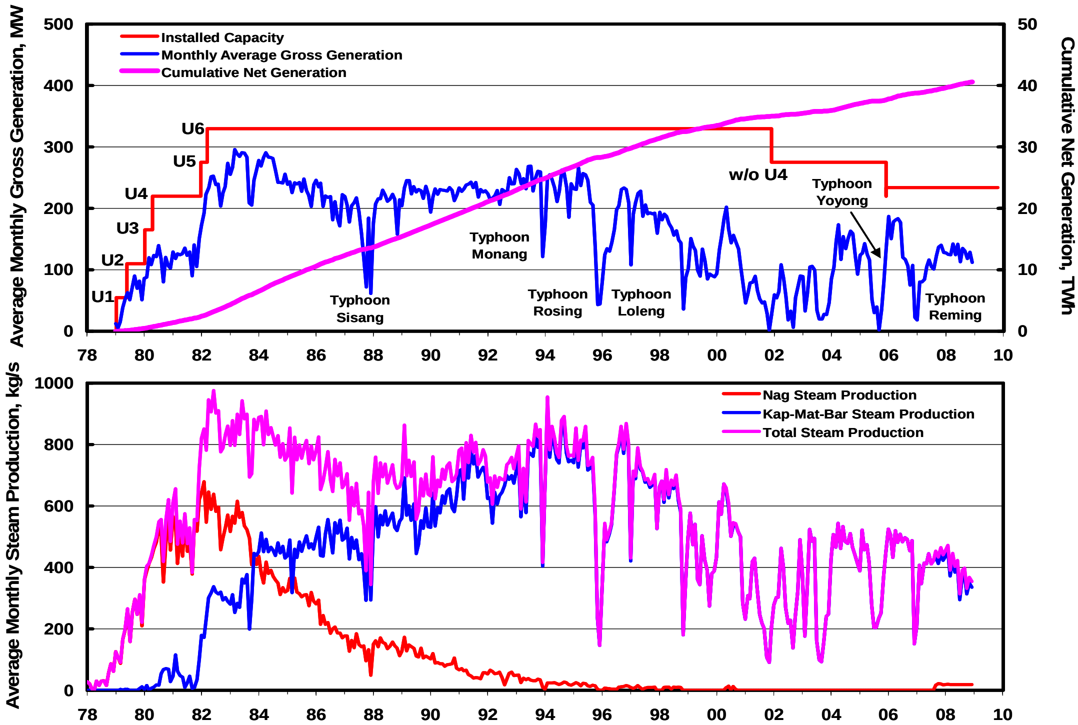

Figure 5: Tiwi Generation and Steam Production History

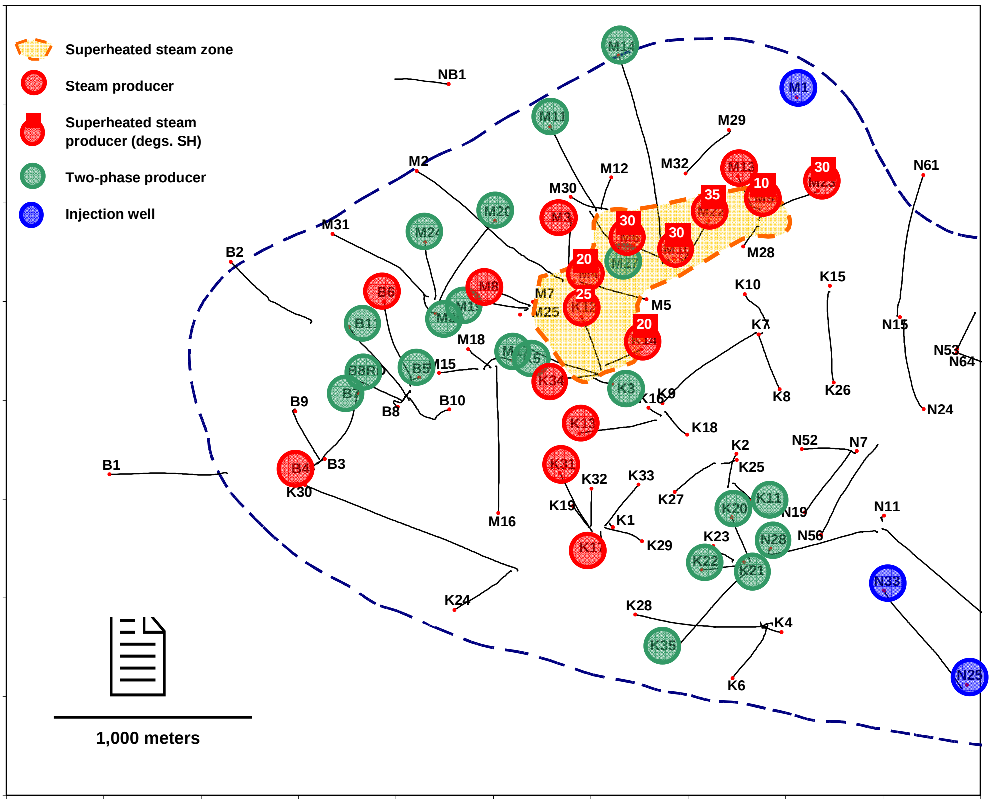

Figure 6: Tiwi Production Well Locations and Production Characteristics, December 2008

4.1 Brine Disposal

In the initial development of the Tiwi field, all separated brine and condensate was disposed of via canal to Lagonoy Gulf (Figure 1). However, this was reviewed early in the operation of the field, in part due to the high initial pressure drawdown, and injection was started in Nag in 1983 using existing wells that had encountered acid fluids (Santos and Carandang-Racela, 1993). However, cooling was detected in nearby production wells and injection was relocated to minimize this effect; first to the SE "edgefield" using existing wells and later to "outfield" injection wells (Nag-66 to 69) located further to the SE. By 1993, all hot and "cold brine" (brine flashed to atmosphere before injection) and condensate was being injected at various locations.

In the Mat and Bar areas, there was initially only a small amount of brine produced, due to the number of dry steam wells, and the cold brine was initially injected to Mat-21, which was drilled in 1992. In the late 1990's there was a significant re-design of the "Mat-Ridge" production system and Mat-21 was converted to hot brine injection, with Mat-1 available as a back-up cold brine injector. In 2005, Mat-21 was re-drilled and Mat-33 was drilled from the same location to provide additional injection capacity as the capacity requirement had increased significantly due to the reduction in overall steam flash from 72% in 1996 to the present value of 40%.

5. CURRENT RESOURCE CHALLENGES

Tiwi has been subjected to virtually all the resource challenges that are common to geothermal reservoirs since starting commercial production in 1979 and these have been previously discussed in Barker, et al. (1990); Gambill and Beraquit (1993) and Sugiaman, et al. (2004) among others. In the following sections, the major challenges that are affecting current production and will potentially affect future production are discussed.

5.1 Meteoric Recharge (MR)

Even before the start of commercial production in 1979, deep reservoir pressures in Nag were declining and by 1983, they had decreased by over 4MPa. The decline in pressure and associated drop in water level caused the formation of an extensive steam zone in the Nag area. However, it was also found that the Cl content of produced brine was decreasing as early as 1977 (Gambill and Beraquit, 1993), indicating that cooler, dilute groundwater (meteoric recharge-MR) was entering the deep reservoir. The MR moved rapidly through the reservoir and as early as 1982-83, it was affecting most of the Nag production area, based on Cl dilution trends. It also contributed to calcite scaling both in the wellbore and formation as it mixed with reservoir fluid. With both processes occurring, Nag steam production reduced significantly (Barker, et al., 1990) and new make-up wells were drilled progressively to the west so that by the mid-1990's all production was from the Kap-Mat-Bar sectors.

To monitor the movement of MR, Tritium has also been used as a tracer as it has the advantage over chloride that samples can be taken and analyzed from steam wells. The tritium contours (Figure 7) clearly show how the MR front has moved from Nag towards the west over time and how it has stabilized as of 2003. The stabilization is due to the semi-permeable barriers associated with the Tiwi and Kagumihan faults although there has been movement across the Kagumihan Fault in the north along its intersection with the Naga fault (Sunio, et al., 2005). The tritium anomaly in the northwest suggests there may be other sources of MR from the north or northeast of the Mat area. The tritium contours also show that South Mat and Bar have not been affected by MR and this is also probably due to structural control.

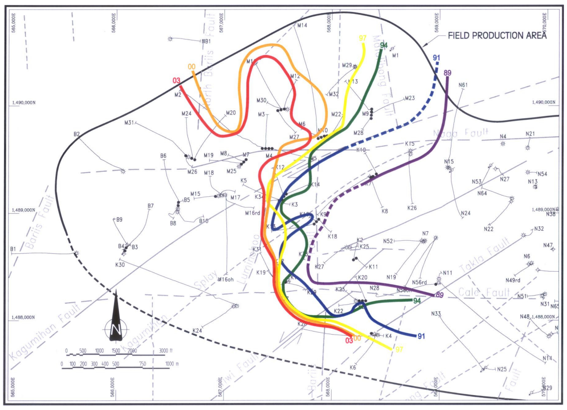

Figure 7: Tritium Contours showing Movement of MR "Front" with Time

In recent years, a number of wells have stopped producing and in some cases, this is believed to be due to MR, based on fluid chemistry changes. In contrast, the South Kap wells (Kap-20, 21 and 22), which have a long history of increasing mass flow and constant enthalpy production, are possibly gaining support from MR or injected brine.

Meteoric recharge will continue to be a challenge in the future, particularly as it is a natural process over which we have little control. It is also becoming more difficult to track, as tritium is becoming less useful as a tracer due to its natural decline in concentration. Repeat precision gravity surveys are also being used to monitor mass changes in the reservoir and this technique has proven to be very useful in showing where changes are occurring and possible locations of mass inflows. These surveys are being conducted every two to three years, with the next survey planned for Tiwi in 2009.

5.2 Production of Acid-Sulfate Fluids

During the initial development of the Nag area, a number of wells were found to produce acid-sulfate fluids. As production moved further west, some wells drilled in the southern area of the field from Kap and Bar encountered acid fluids and in 2008, the presence of acid fluids was also found in the North Mat area. If the produced fluid from these wells has a pH above 4.0, they are normally flowed to the system but their discharge chemistry, particularly pH and Fe concentration is carefully monitored as per set guidelines (Villaseñor, et al., 1999) to ensure that corrosion is not occurring in the well and they will not cause corrosion in the surface facilities.

In 2000, Bar-08 was flowed while injecting sodium hydroxide through capillary tubing installed in the well to neutralize the acid. This was successful for 3 months but when attempting to pull the tubing for inspection, the injection head was found to be scaled into the wellbore. A workover was conducted but it also failed to recover the tubing and finally the liner was pulled. During this operation, corroded liner was recovered, which provided a good indication as to the depth of the acid inflow zone. No further attempts at downhole mitigation have been tried.

More recently, changes have been made to the well design to be used in these areas, with a cemented blank liner run to below -1,000m msl to case off potential acid zones (Villaseñor, 2009). This was first tried in the redrill of Bar-08 in 2006, which had previously produced acid fluids. After being recompleted, it produced benign fluids and is now one of the largest producers in Tiwi. In 2008, Bar-11 was drilled and completed with the same casing design and is also producing benign fluids. These results provide confidence that wells can be completed successfully in the south and southwest areas which were previously considered non-producible due to acid fluids.

5.3 Injection Breakthrough

When injection first started in the Nag area in 1983, cooling was quickly observed and injection was relocated to the southeast "edgefield" and "outfield" wells. Since then, there have not been any significant thermal breakthrough issues but to help prevent this from occurring, limits have been placed on the allowable injection rates in specific wells and production wells considered to be "at risk" are carefully monitored. Tracer tests have also been conducted to check the connectivity of the "edgefield" injectors in the southeast to production wells located near the southern boundary of the field. The results showed communication between the edgefield injectors and the Kap production area but the peak return concentrations and overall tracer recovery were very low, suggesting the risk of thermal breakthrough is correspondingly low. The main avenue for possible breakthrough is thought to be the Cale fault, which is nearby or intersected by some of the wells in which tracer returns were found.

In the Mat area of the field, some of the dry and superheated steam wells have turned two-phase over the past five years and there is a possibility this might be associated with injection, particularly to the cold brine injector, Mat-1, and also to an increase in hot brine injection at the main injectors, Mat-21 and 33. This is discussed further in Section 5.4. Tracer tests conducted in 2008 show that there is connection but further studies are required to determine if the connection is significant enough to cause long term damage to the production reservoir.

With the reduction in overall flash fraction mentioned in Section 4.1 and the likelihood that this will continue into the future as production becomes dominated by lower enthalpy wells, there will be a continuing need to review the injection strategy and possibly find new injection sites if the capacities of the existing injection wells are exceeded. This will require a continuing program of chemical monitoring, flow testing and tracer testing under various scenarios.

5.4 Matalibong "Superheated" Steam Zone

The increased extraction from the Mat area in the early 1990's caused extensive boiling to occur as the pressures declined, forming a reservoir zone that produces "superheated" steam. The presence of superheat was first measured in the mid-1990's although superheating had been measured as early as 1991 in some wells (Lim, 1997) and had probably started to occur in the late-1980's.

Along with superheated steam, the wells also produced volatile Cl (Sugiaman, et al., 2004), which formed very high, localized, concentrations of HCl where condensation occurred in the pipelines, resulting in accelerated corrosion. Scaling also occurred where the superheated steam mixed with two-phase fluids in the wellbores and pipelines. To mitigate corrosion, the "Mat-Ridge" production system was redesigned to inject sufficient separated brine into the steam pipelines to prevent the high, localized HCl concentrations. This has been very effective and with the increasing brine production in recent years, there is no longer a significant risk to the surface facilities.

Since 2001, the Mat superheated steam zone has lost 76kg/s of flow due to the water level in the reservoir rising and "flooding" zones that used to produce steam or superheated steam. The rise in water level is due to a combination of increasing deep reservoir pressure and declining steam zone pressure. Once flooded, the zone(s) produce liquid water and if the well has no significant shallower zones, then it is likely that it will stop producing. If it does have shallower zones, then it will continue producing but at a reduced flow rate and lower enthalpy.

The 12 wells presently producing from the Mat steam zone provide 140kg/s steam or 33% of the total steam available at the present time. Hence, it is an important area for production. The rising water level can be mitigated if deep pressures decline and/or steam zone pressure can be stabilized or increased. Both deep reservoir and shallow steam zone pressures are now being monitored on a continuous basis to help develop a strategy to maintain production from the steam zone into the future. If the water level can be reduced, it is anticipated that previously affected wells may be able to produce again although there is also a risk that any reduction in deep pressures may result in an influx of MR from the field margins.

CONCLUSIONS

After 30 years of commercial production, most of the common challenges faced in developing and managing a geothermal resource have been encountered at Tiwi and have either been overcome or mitigated. The biggest challenge was the MR in the Nag area, which occurred within the first 3 years of operation and necessitated the relocation of the entire production system. The key to overcoming these challenges has been to have a strong multi-disciplinary resource team in place that can quickly understand and react to the issues and provide workable solutions.

At the present time there are 37 production wells in the field, including Bar-11 and Kap-35, the two wells completed in 2008. The successful completion of these two wells opens up additional possibilities for locating future production wells to the south and southwest of the Kap and Bar sectors that will help maintain production in the future at or above the present level of 430kg/s (190MWe). However, it will also require additional investment in the existing surface facilities, with particular emphasis on injection as brine production is expected to increase as a consequence of declining overall flash fraction.

It is recognized that there will continue to be challenges in the future at Tiwi, but CGPHI are confident that they can and will be overcome and Tiwi will continue to be a reliable producer of electrical power to the Philippine national grid for many years to come.

ACKNOWLEDGEMENTS

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