MITIGATION OF CORROSION IN AN ACID PRODUCING WELL AT TIWI GEOTHERMAL FIELD

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ABSTRACT

Acid-sulfate fluids are present in most exploited and explored geothermal areas in the Philippines. Existing acid wells are mostly shut-in due to their high corrosion rate despite proximity to operating power plants. At least 80 MW of proven generation is currently unavailable in producing fields due to acid-sulfate fluids, and the potential generation from acid-sulfate fluids nationwide could easily exceed 300 MW. These estimates highlight the current potential value of acid-mitigation technology to the Philippines in terms of indigenous energy production, but development of cost-effective corrosion mitigation technology is needed to realize this value.

. The Bariis-8 production well at the Tiwi geothermal field produces acid-sulfate brine exhibiting a pH as low as 3. Wellhead piping experiences significant corrosion if produced as is. Short-tern tests demonstrated that corrosion maybe mitigated by neutralizing the acidic brine with sodium hydroxide, or by addition of filming amine-type corrosion inhibitors. Commercial production of the well has been achieved by injecting dilute NaOH solution into the well at a depth of nearly 1,000 m employing high alloy capillary tubing and specially-designed injection nozzle system. Although wellhead corrosion can be mitigated by injecting NaOH solution just below the master valve, deep injection into two-phase fluid has been utilized to prevent casing corrosion. The pH of the brine at the wellhead was increased from -3 to ~5. Corrosion of the wellhead and surface piping decreased by more than 50%. Corrosion mitigation of Bariis-8 contributes 7 MWe of additional power to the Tiwi field output. The success of the corrosion mitigation effort is attributed to an interdisciplinary team approach to design, testing, and implementation of the system. Resulting design features include alloy capillary tubing, lubricator, tubing injection stinger, pack-off assembly, injection nozzle configuration, caustic solution strength, duplex pumping system, distributive control system, and on-line monitoring equipment have all contributed to system function.

1.0 INTRODUCTION

Wells that produce acid-sulfate brine are encountered in several Philippine geothermal fields, in addition to scattered fields around the world (Sanchez Rivera et al., 2000). The Tiwi geothermal resource consists primarily of a neutral chloride reservoir. However, similar to other Philippine geothermal fields like Tongonan, Southern Negros, Bacon-Manit0 and Mt. Apo, small, isolated pockets of acidic fluids occur. Most wells producing acid-sulfate fluids are shut-in due to their high corrosivity despite proximity to operating power plants, although some are utilized for brine disposal. It is estimated that about 83 MW of proven generation is currently unavailable in producing fields in the Philippines due to acid-sulfate fluids. Added unproven generation in these fields from acid-sulfate sectors is more speculative, but may total 150 MW, if large-scale mitigation efforts were to prove economic. Major portions of the Philippine geothermal prospects at Mt. Labo, Mt. Pinatubo (Delfin et al., 1996), Biliran, and Alto Peak have acidic reservoir fluids (Ramos-Candelaria et al., 1995; Reyes et al., 1993). Many other unexploited prospects have not been drilled because they have brine and gas chemistry that indicates the presence of acid-sulfate fluids. Thus, the potential generation from acid-sulfate fluids in the Philippines alone could easily exceed 300 MW. These estimates highlight the current potential value of acid-mitigation technology to the Philippines. This paper describes successful corrosion mitigation of acid-sulfate brine in a well at the Tiwi field.

2.0 BACKGROUND

Corrosive geothermal wells have been encountered in both vapor-dominated and liquid-dominated reservoirs. Hydrochloric acid corrosion was initially reported in superheated steam wells at the Larderello, Italy field (Allegrini and Benvenuti, 1970). Upon exploitation of the Geysers, California field, HCI corrosion deleteriously affected several production wells. UNOCAL initiated corrosion mitigation efforts in 1985. Commercially-available inhibitors were tested at one well, together with caustic neutralization (Gallup and Farison, 1998). Eventually, several operators at the field installed caustic injection systems (Bell, 1989) to treat acidic steam at the wellhead. Other operators attempted downhole NaOH injection, but these systems were complicated and required excessive maintenance (R. Fosse, pers. comm.).

In the mid-1980s, Philippine Geothermal, Inc. (PGI) drilled several wells that produced acid-sulfate brine at the Tiwi field. These wells encountered advanced argillic alteration mineral lenses. Core retrieved from well Kap-4 consisted of pyrophyllite, diaspore, alunite, anhydrite and quartz (in that order of abundance). This well was eventually re-completed (the advanced argillic lens was cased over) and now produces benign brine. Well Sad-I drilled to the S of the main field was too corrosive to be successfully flow tested. This well was treated with soda ash solution to neutralize the acid corrosion. However, overdosing with soda ash resulted in carbonate scale deposition in surface flow test equipment.

CHILLER modeling Spycher and Reed (1992) and laboratory core-water reaction studies showed that contacting neutral brines with the advanced argillic rocks produces low pH acid-sulfate brines. In addition to this mechanism, other hypotheses to account for acid brine have been suggested (Kiyota, et al., 1996). At Tiwi the acid fluids are most likely produced either by shallow (<3000' bsl) oxidation of ascending gases and rock-water interaction or migration of shallow acid fluids from the upper reaches of Mt. Malinao (previously suggested in Fig. 7 of Hoagland and Bodell, 1991).

Bar-8 Well

Bariis-8 (Bar-8) well at the Tiwi field initially produced saturated steam and minor amounts of neutral brine. After a required shut-in for several months, the well was again placed on production. With time, the well began to produce more and more brine that was increasingly corrosive. Early in 2000 it produced a mixture of acid-sulfate and neutral fluids (pH typically 3.5 to 3.8). Since this well can produce 7–10 MW of steam, PGI selected it for testing corrosion mitigation measures. Short-term flow tests were conducted in 1998 to examine treatment of commercially-available inhibitors and caustic neutralization at the wellhead. Although the filming amine inhibitors successfully controlled corrosion, the manufacturers do not recommend their use above ~200°C. Caustic treatment proved to economically control corrosion upon raising the brine pH to ~5–6. At the conclusion of these demonstration tests PGI concluded that corrosion was occurring below the wellhead, and therefore, corrosion mitigation was required deeper in the well at temperatures above those tolerated by the filming amines.

Employing the results and understandings gained in the surface injection tests, a commercial operation using downhole NaOH injection was planned. This operation required designing a corrosion mitigation system that could deliver concentrated NaOH to ~1070 m into the well (below the deepest advanced argillic alteration lens). Nova Technologies (Lafayette, LA) assisted PGI in the design of an injection sub with spray nozzles, weight bars, a centralizer and a sub check valve. Inconel 625 was selected as the material for the injection sub assembly and the 12.7 mm OD capillary tubing. Additionally, 48 wt% NaOH solution' purchased in bulk was diluted to 4 wt% with fresh water to prevent excessive alloy or easing corrosion/cracking. The diluted NaOH also allows easier dosing over a wide pump turndown. We specifically elected not to inject concentrated caustic or use Incalloy 825 materials as installed at Miravalles field, Costa Rica to reduce the potential for alloy cracking (cf. Sanchez Rivera, et al., 2000).

Figure 1 shows a diagram of the surface equipment. At the surface, 4 wt% NaOH is prepared in batches and stored in tanks. Small injection pumps are installed between the feed

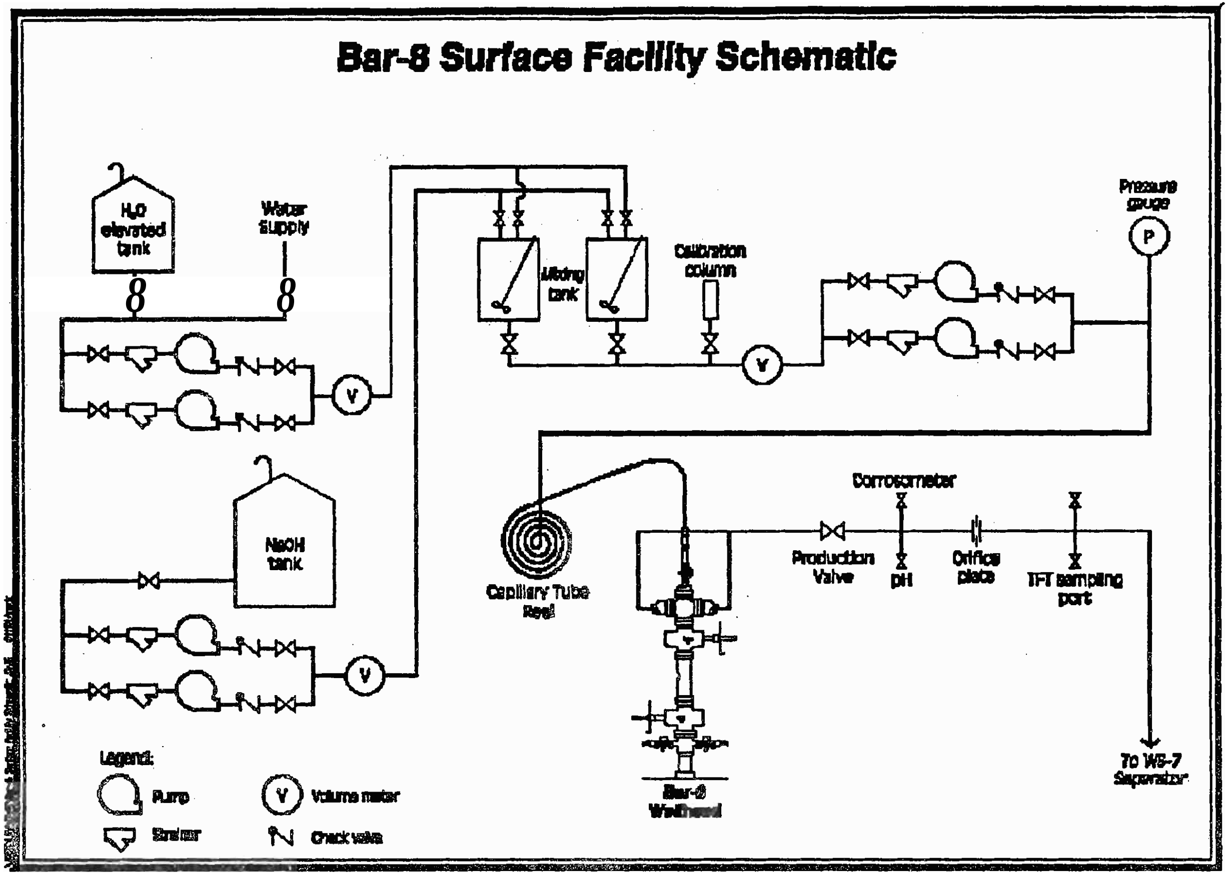

Figure 4. Surface facilities for caustic preparation and system monitoring and **control.**

tank and the capillary tubing spool. Flow and injection pressure monitoring equipment are installed at various points along this line. Corrosion rate is measured by an on-line corrosometer probe **located** at the two-phase production **line.** Fluid pH **is measured** continuously through a small sampling train. All these data are recorded by a Delta V monitoring and control system which also sends real time data to the plant station for operator monitoring of the process.

The injection rate of the caustic solution is manually adjusted based mainly on the fluid pH. The batch preparation **of** the caustic solution **is** mainly controlled through the Delta V system **though** this tedious process could **also** be done manually.

Some operators requiring downhole chemical treatments have utilized side entry spools to install capillary tubing below the master valve. We elected to inject the tubing **through the** top **of** the well using a special stinger that was positioned across the tee to minimize mechanical abrasion. Two master valves were used to facilitate run-in and pull-out of the injection assembly without killing the **well,** Production valves were placed at the cross tee of the well so that shut-in can be accomplished without cutting the tubing upon closing the master valves.

2.0 CORROSION MITIGATION OF BAR-8

In March 2000, the surface facilities were completed and the downhole assembly was delivered. The injection assembly/tubing was lowered into the well while flowing fresh water through the tubing. On April 2, 2000, NaOH injection was initiated while flowing the well to a sump. During the first two weeks of operation, the system was de-bugged and corrosion rates were monitored using coupons and corrosometers. **Brine** pH and composition were monitored to ensure that corrosion was under control and that the brine was **properly** titrated

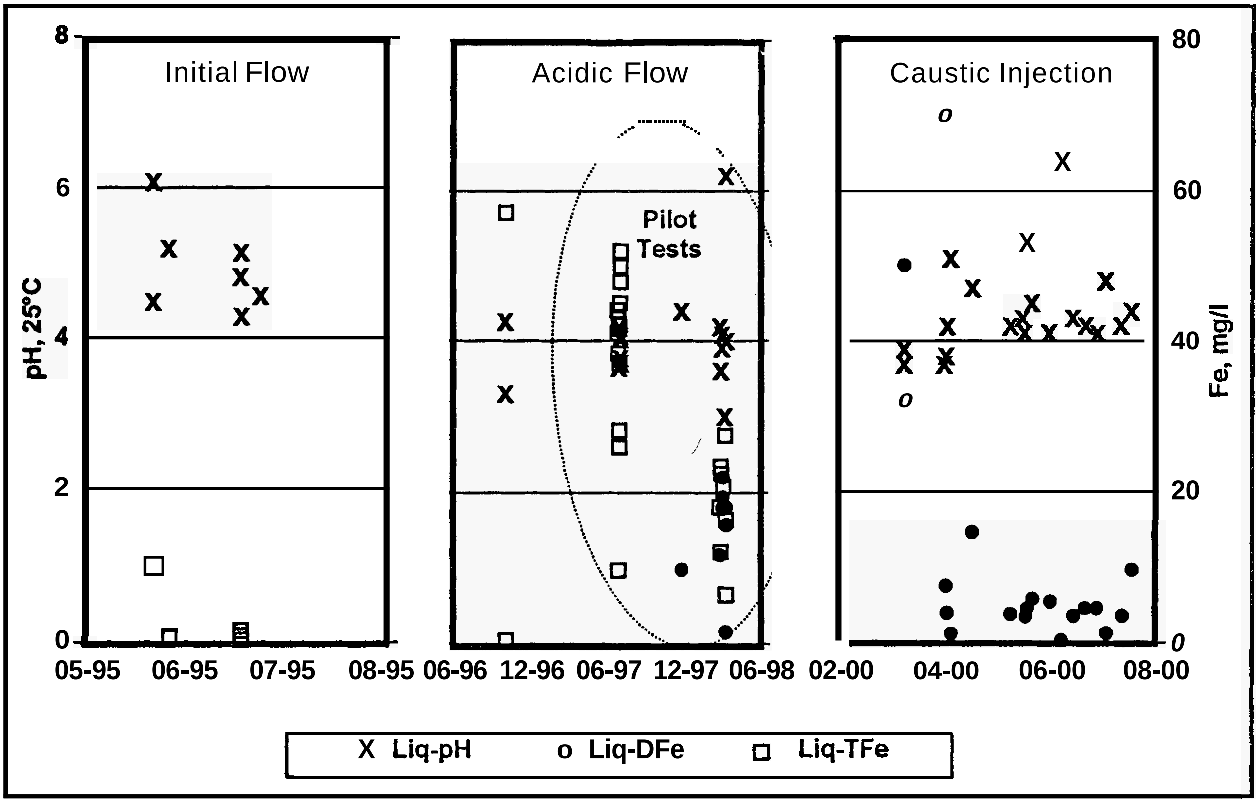

Figure 2. **Fluid pH and** iron concentrations **of** Bar-8

with NaOH. Attempts were made to control the brine pH between 4.5 and 5.0. Overdosing with NaOH (> 6.0 brine pH) had been shown to exacerbate silicate scaling. The well was then produced to the Tiwi steam gathering system for three months. Figure 2 shows the pH and iron concentrations achieved at the surface during this interval (dFe is dissolved iron in brine and TFe is total iron in brine). The dissolved iron concentrations during the mitigation showed a reduction of greater than 80%. The well contributed 7 MW of steam to the Tiwi power plants.

In July 2000, the well flow decreased slightly and the commercial mitigation operation had met most of its objectives. The well was shut-in for a planned inspection of the injection assembly and a well caliper survey. Efforts to pull the injection assembly out of the well have been unsuccessful to date. Bar-8 is currently shut-in for safety considerations pending further attempts to retrieve the injection sub. Sub modifications may be required to prevent future sticking, and the well will be returned to commercial operation.

3.0 BENEFITS OF ACID-WELL CORROSION MITIGATION

Corrosion mitigation has high potential value in the Philippines, however, not all of the acid-sulfate wells in the country may be as easily mitigated as Bar-8. A significant number of other acid-sulfate wells have pH<3.5, and may prove slightly more difficult and costly to mitigate and produce long-term. For example, a PNOC-EDC mitigation test of an acid well (pH about 3.2) at Mahanagdong in 1999 was largely unsuccessful (Villa et al., 2000). However, the successes achieved at Bar-8 imply that with sufficient planning and investment, most acid-sulfate wells can probably be neutralized to allow commercial production. Successful mitigation of a more corrosive well at Miravalles shows that this is possible (Sanchez Rivera et al., 2000).

Minor active corrosion that occurred during the Bar-8 commercial operation and during demonstration testing may have reduced the casing life of the well. In addition to the issue of corrosion, formation of anhydrite scales in wells, or other scales (in pipelines) due to mixing of different fluids may complicate mitigation success and reduce well productivity (Vidal et al., 1998). Despite these challenges, PGI is confident that corrosion mitigation can be successfully applied to new areas, if sufficient technical and financial resources are available. Plans to mitigate corrosion in other Tiwi wells are underway.

Successful application of corrosion mitigation potentially opens drilled, but undeveloped areas, such as Mt. Labo, Mt. Cagua, Alto Peak, and Biliran Island. Outside the Philippines, fields can potentially be developed in Taiwan, South America and Indonesia if corrosion mitigation were successfully applied. Furthermore, a number of additional prospect areas have spring and fumarole chemistry that suggests acidic fluid chemistry and has discouraged further work. Corrosion mitigation potentially allows development of these acidic areas.

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