EXAMPLES OF CORROSION MONITORING AT TIWI GEOTHERMAL FIELD

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ABSTRACT

The corrosion monitoring team in the Tiwi Geothermal Field is a multi-disciplinary group from geoscience, operations, drilling, and engineering that has developed a unified corrosion monitoring program. Based on a set of geochemical parameters, engineering standards and decision trees, the corrosion monitoring program outlines the schedules for geochemical sampling and ultrasonic thickness gauging. The results of these measurements provide input to the planning of the replacement and repair of the surface reticulation equipment, reduction or increase in the monitoring frequency, and rarely, shutting-in of wells. Less frequent activities such as corrosion monitoring through the use of in-line corrosometer probes and caliper surveys of wells are also included in the program. Through this systematic approach, the nature of the corrodant, location of the most affected sections of the pipelines and the concomitant activities that can prevent or minimize the effects of corrosion are identified.

Corrosion in Tiwi has been ascribed to the presence of acid sulfate fluid in the reservoir and the production of volatile chlorides from areas of superheat and dry-out. Presence of brine carryover or steam condensates in the steamlines also contributes to the corrosion. The geochemical samples collected from wells that are found to discharge acid sulfate fluids are mainly separated liquid and gas samples. Wells with volatile chlorides are monitored by collection of steam condensate and gas samples. The frequency of the collection of geochemical samples to monitor these corrosive fluid is based on the corrosion level determined by the decision trees and the corresponding inputs from chemistry and the non-destructive testing (NDT) group.

Management of the corrosion allowance included in the design of the pipelines uses the output of the corrosion team in programming for the replacement of piping segments that fall within the critical region In rare cases of wells or pipelines that show excessively high corrosion rates, shut-in or isolation is recommended and mitigation measures are instituted

1.0 INTRODUCTION

The first geothermal systems that were harnessed for power generation were those at Larderello and the Geysers. These are steam-dominated systems that produced 'clean' steam. Succeeding geothermal systems that were developed for power generation were of the water-dominated type like those at Wairakei, Tiwi, MakBan, and Tongonan. For these latter installations, separation of brine from steam is required. In many cases, the power plants have also had to be designed to scrub the considerable amount of non-condensable gases from the separated steam like at BacMan. Due to the increasing demand for electricity, geothermal developers have to move on to the 'less attractive prospects' that may not have the desired temperature, resource size or reservoir fluid quality. Major portions of the Philippine geothermal prospects at Mt. Pinatubo (Delfin et al., 1996), Biliran, and Alto Peak have acidic reservoir fluids (Ramos-Candelaria et al., 1995; Reyes et al., 1993). Present technology for the exploitation of fields with corrosive fluids is expensive if not unavailable.

The Tiwi geothermal resource consists primarily of a neutral chloride reservoir. However, similar to other Philippine geothermal fields like Tongonan, Southern Negros, Bacon-Manito and Mt. Apo, small, isolated pockets of acidic fluids occur. This is a normal occurrence since geothermal fluids possess considerable amounts of chemically aggressive gases such as CO_2 and H_2S. It is therefore reasonable to expect that corrosion will take place not only on surface pipelines but also on well casings especially in the acidic or gassy sections of the reservoir.

One of the tasks of current geothermal fluid handlers therefore is to find cost-effective ways of managing corrosion. In the design of a geothermal power facility, as in other power plants utilizing steam as a medium, this is taken into consideration and a corrosion allowance is included in the design. Proper management of this corrosion allowance should ensure the smooth and economical operation of geothermal fields.

At Philippine Geothermal, Inc. (PGI) a corrosion team is tasked to monitor corrosion, characterize corrodants, identify corrosion mechanisms, implement corrosion mitigation systems, and maintain the safe operation of surface pipelines and wells. This multi-disciplinary team is composed of engineers and geochemists fiom operations and production engineering, drilling, and geoscience. This group uses geochemical methods, physical measurements of metal thickness and other tests to gauge the amount of corrosion that has taken place or is expected. The source and mechanism of corrosion can then be understood and an effective mitigation method can be implemented.

2.0 METHODOLOGY

In PGI's Tiwi field, corrosion is monitored by chemical and non-destructive techniques. Particular attention is given to wells and pipelines which show indications of accelerated corrosion rates (> 5 mils per year or 0.127 mm/yr). For these wells or pipelines, geochemical sampling and ultra-sonic thickness measurements are done more frequently not only to monitor the advance of corrosion but also to understand the mechanism of corrosion. Wells that show excessively high corrosion rates are taken off-line while mitigation procedures are being designed and implemented.

3.0 TIWI CORROSION MONITORING PROGRAM

The Tiwi corrosion monitoring program is relatively new in that it had been applied only in the past two years. As it is, it is a living document where adjustments are still being made. Currently it is a set of guidelines that aid in the systematic determination of the presence of corrosion, its severity and the classification of the corrosion type. It also defines the subsequent activities to be undertaken once corrosion has been characterized. The data gathered is used in characterizing the likely corrosion mechanism so that an appropriate mitigation system can be developed. This information also aids in the identification of other wells or pipe sections in a similar situation and therefore requires the similar activities of monitoring and study.

4.0 GEOCHEMICAL MONITORING

The types of geochemical samples collected range fiom steam and separated liquid samples to scale or corrosion products. The minimum required analyses for separated steam and liquid samples are pH, Fe, SO_4, Cl, Mg and SiO_2. Based on these parameters the corrosive potential of a fluid or the presence of corrosion and its severity are determined. The corrosion levels grade fiom Level 1 (highly corrosive) down to Level 2 (moderately corrosive) then Level 3 (slightly corrosive). The following figures (Figures 1 and 2) summarize the Tiwi Corrosion Monitoring Program.

The flowchart in Figure 1 can be used for both steam and liquid samples. The upper portion determines whether corrosion is already taking place or if the fluid chemistry shows that it has the potential to cause corrosion. The main determinant here is the iron concentration since Fe counts often suggest that corrosion is actively taking place. When both the SiO_2 and Cl are high, this implies that the sample contains some brine carryover in the steam that is a product of poor separation. In this case, for example, if the sample was taken fiom a steam line, then the separator upstream of the sampling point is not working properly. Or if the sample was taken fiom a two-phase line through the use of a mini-separator, then it could be a sampling error.

Through the use of the pH, Cl, SO_4, and Mg analyses, the bottom half of Figure 1 determines the potential of the fluid to cause corrosion as well as the possible nature of the corrodant. A separated liquid sample that has low pH, high SO_4 and Mg, for example, typically indicates the presence of an acid sulfate fluid.

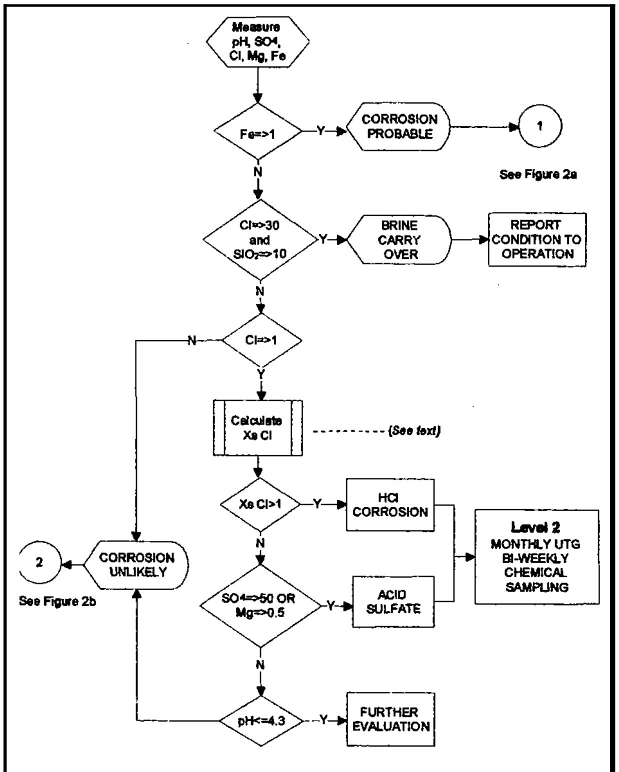

Figure 1

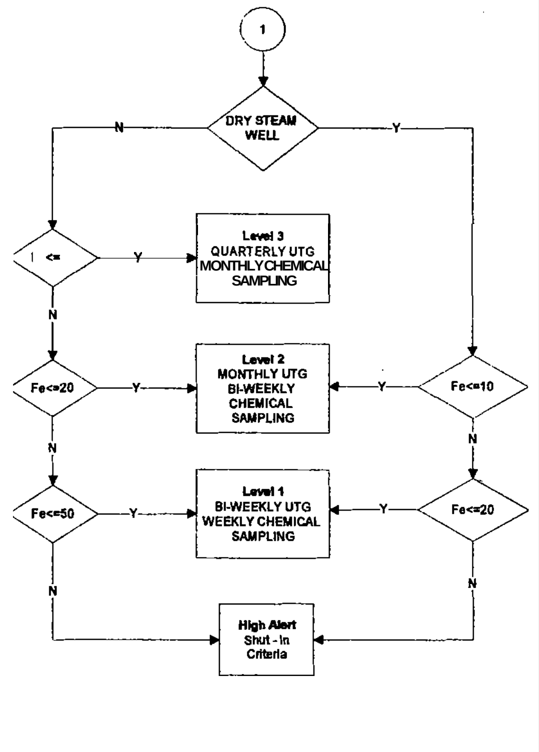

Figure 2

The term Xs Cl is calculated from the chemistry of superheated steam samples that have low pH. It refers to chloride that is in excess of the stoichiometric amount required to balance the Na, K and Ca concentrations in brine. It is calculated from the equation:

$$XsCl = 35.453 * \left\{ \left(\frac{ppmCl}{35.453} \right) - \sum \left[\left(\frac{ppmNa}{22.9898} \right), \left(\frac{ppmK}{39.102} \right), \left(\frac{ppmCa}{20.04} \right) \right] \right\}$$

Excess chloride is used to determine the presence of volatile chloride in steam samples where it is usually in the form of HCl. It is believed that the primary source of volatile chloride for exploited geothermal fields is the drying out of the reservoir (Truesdell, et al. 1988) while it may be different for younger geothermal systems where one could invoke a magmatic origin (Giggenbach, 1987; Ramos-Candelaria, 1995).

Once it is determined that a well has the potential to be corrosive, either by HCl or H_2SO_4, it is placed at Level 2 so that more data can be gathered at once to ascertain the mechanism and possible mitigation procedures to apply.

The cut-off values for pH, Fe, SO„, XsCl, Cl, SiO_2, and Mg quoted in Figure 1 are quite arbitrary and may depend on the *background* for the field or the source of the sample. Samples collected at atmospheric conditions would have higher concentrations since these would have lost more steam. Some fields may also have SO_4 concentrations that are greater than 50 ppm and still not cause considerable acidity.

Figure 2 shows the branch of Figure 1 that deals with the condition where Fe is higher than 1 ppm, i.e., when corrosion is already taking place. The first decision point separates the steam samples from the liquid samples. The basic assumption is that Fe from the reservoir fluid is not transported with the steam phase such that any iron in a pure steam discharge is due to corrosion. The differences in the corresponding alert level for a given Fe concentration from either a liquid or steam sample is also due to the presence of some Fe in the reservoir fluid that can be transported by the fluid Hence, wet discharges can have 20 ppm Fe and be at Level 2 while dry steam discharges are placed at Level 1 if the iron content is between 10 and 20 ppm.

The alert level then defines the frequency of collecting geochemical samples and taking ultra-sonic thickness (UT) measurements. For example, geochemical samples from wells in Level 3 are collected monthly while UT measurements are performed every 3 months.

The results of the geochemical monitoring are compiled into a corrosion watchlist where the recommended monitoring frequency both for geochemical sampling and UT measurements are reiterated as well as additional studies are recommended In cases where a well is classified as Level 1, a review of the well's corrosion history is included together with a recommendation to shut the well in or mitigate its corrosivity. In other cases, the chemistry of the well changes such that it becomes benign, it is removed from the corrosion watchlist and its monitoring (geochemical and UTG) reverts back to its regular monitoring scheme. Well Mat27, a dry steam well, has previously showed condensate pH values which are slightly below 4.3 as well as fluctuating Fe and Cl concentrations. It was thus classified as Level 3. When the condensate pH and Fe levels showed improvements it was taken off the corrosion watchlist. Mat30, a wet well, has been included in the watchlist due to low pH and high SO_4. Later, the fluid pH improved while the sulfate concentrations remained high and after a few more months of confirmatory corrosion monitoring it could be taken out of the corrosion watchlist.

Solid samples such as corrosion products taken during visual inspection of pipelines or brief shutdowns are normally analyzed by XRD. Characterization of these samples and correlation with the fluid chemistry aid in the elucidation of the corrosion mechanism. For example, in one section of the Matalibong steam line, minimal pyrite was seen during visual inspection. However, based on Pourbaix diagrams pyrite is predicted to be stable at those conditions and should form a protective film on the metal surface thus preventing further corrosion of the pipe wall. The absence of significant pyrite and the accelerated corrosion rate observed in this steam line lead to the conclusion that the pyrite protective film must have been disrupted by solids, brine carryover or steam condensate thus exposing more fresh metal to corrosion (Gallup, 1997).

5.0 ULTRA-SONIC THICKNESS GAUGING

Measurements of the thickness of pipelines are done routinely by the non-destructive testing group. The measurements along installations that are not on the corrosion watchlist are normally taken once every two years. The collected data is downloaded directly from the instruments into a PC where the *UltraPipe* software plots and calculates the data based on PGI's design manual. The software then outputs the corrosion rate, remaining life, and the schedule of the next test.

The ultra-sonic thickness (UT) measurements provide information on where the actual corrosion is taking place. This plays an important role in the cost-effective design of a corrosion mitigation plan. In many cases, higher Corrosion rates are obtained from pipe sections where there is turbulent flow. This is probably due to the disruption of the protective film on the pipe wall exposing more fresh metal for the corrodant to attack During the flowtest of well Bar10, for example, it was observed that the elbow at the end of a long straight run had the highest corrosion rate, probably not only due to chemical attack but also because of erosion. The elbow was then replaced with a simple cross tee with one end fitted with a blind flange. This set-up not only provided a cushion which minimized the erosive force of the oncoming fluid but it also minimized the cost of replacement since only a corroded blind flange needs to be changed instead of a whole elbow.

Figure 3 shows the decision tree based on the UT measurements. The first column of decision boxes refers to the calculated corrosion rates while the middle column uses the remaining life as the basis for a decision or action. The corrosion rate (CR) can be expressed as mils per year or µm per year (1 mil ≈ 0.0254 mm ≈ 25.4 µm) and is calculated either from two successive measurements or the slope of the line that best fits the data points.

The remaining life (RL) represents the theoretical number of years at the current corrosion rate before the minimum allowable thickness (MAT) is reached. The corrosion allowance is the additional thickness over that specified by other design requirements. This additional thickness should be consistent with the expected life of the piping and for design purposes, PGI has used a corrosion allowance of about 1.6 mm for pipes and fittings.

The measurement of the pipe wall thickness is an indication of how fast the corrosion allowance is being depleted. Pipe sections that show rapid thinning or ones where the MAT is almost reached through years of service are inspected more fiequently, and programmed for replacement or corrosion mitigation. In Figure 3, more fiequent inspections for sections that have high corrosion rates and low remaining life is required. Wells or pipe sections that show corrosion rates greater than 30 mpy and $RL \leq 2 years$ are also included in the corrosion watchlist.

In cases when a well or pipe section is classified as Level 2, grid-mapping of critical portions such as elbows or straight pipes downstream of a flow restriction as well as exposed well casings is conducted. This gives better information on the extent of corrosion that is, in a lot of cases, largely affected by the flow regime as mentioned above. Plots showing the depletion of the corrosion allowance, changes in the corrosion rate and remaining life and 3D profile of the mapped section also provide information on the possible corrosion mechanism. At well **BarlO,** intensive monitoring of the elbows at the downcomer and a short straight pipe downstream of the orifice plate provided information on how fast the corrosion was proceeding and some ideas *on* the role of turbulence.

6.0 OTHER TESTS

Confirmatory data is gathered when a well is classified as Level 1 before a well is shut-in. Figure **4** shows the shut-in decision process that the team goes through before recommending a well for shut-in.

A thorough review of previous geochemical data and well performance is performed while intensive geochemical sampling, downhole sampling, flowing PTS, in-line corrosometer and corrater testing, in-line and downhole corrosion coupons, or grid-mapping UT

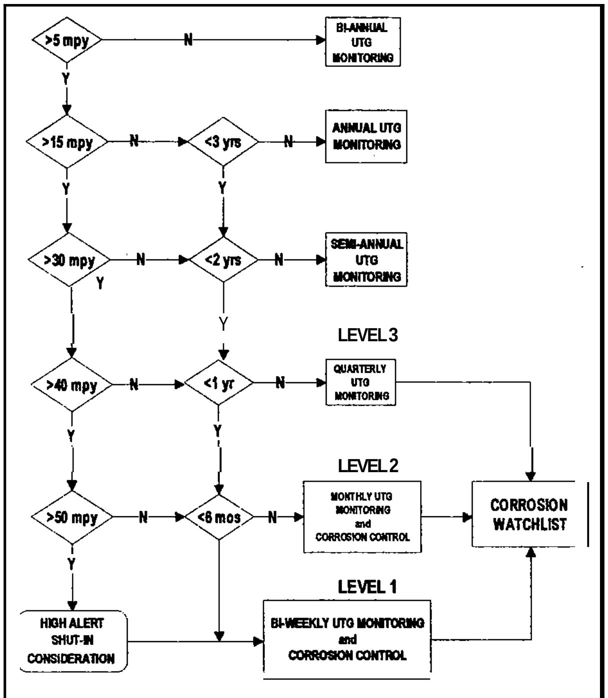

Figure 3

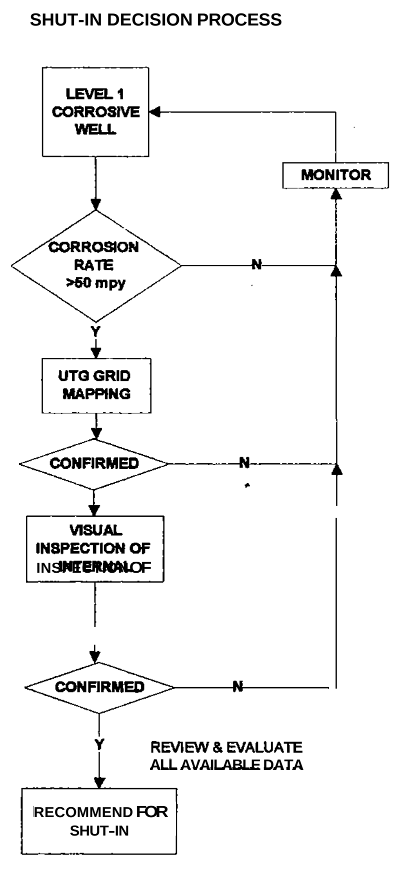

Figure 4

measurements are performed on either the flowing well or during a short flow test. To gain information on the well casing's integrity a caliper survey may also be run. This is followed by visual inspection of the valves, pipes and fittings before a recommendation for shut-in or replacement of the corroded section is forwarded to management.

Apart from wells which are found to be discharging corrosive fluids, UT measurements are also taken fiom steamlines. Twice a year, corrosometer probe tests are conducted on sections which are observed to exhibit high corrosion rates. In these tests, numerous probes are inserted into the different sections and readings are taken at least twice a week for a couple of months. Condensate samples from sections that are likely to contain steam condensate such as dead legs or low spots upstream of vertical loops or long, inclining straight sections are also collected. Spot checks on these condensate sampling points are also done using a simple conductivity meter to determine the presence of brine carryover.

Some of these special tests can also be conducted on wells that have consistently been classified as being corrosive in order to confirm and calibrate the findings of the geochemical and UT measurements. These tests provide information on the source and nature of the corrodant, the corrosion mechanism, and provide a guide in designing the appropriate mitigation method.

The use of this monitoring program has allowed PGI to more effectively understand and control the corrosion problems in the Tiwi Geothermal Field. Currently, we are designing mitigation systems that will potentially allow shut-in Level 1 wells to be returned back to service. For example, experience gained in combating corrosion due to volatile Cl at the Geysers will be applied directly to some wells in Tiwi (Gallup and Farison, 1998).

ACKNOWLEDGMENT

The authors wish to thanks the management of Philippine Geothermal, Inc. for permitting the publication of this work.

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