Corrosion in Air Cooled Condensers - Understanding and Mitigating the Mechanisms

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Abstract:

Corrosion in the air cooled condensors has been a cause for concern for several years in Eskom's direct dry cooling stations. The exact mechanism of the observed corrosion has not been positively identified but is thought to be a form of flow accelerated corrosion.

Eskom has over the years tried several methods to mitigate the corrosion, such as varying the steam/condensate pH as well as the application of certain so-called protective epoxy coatings. There is clearly a link between the observed corrosion and the prevailing pH. Studies have shown a lower rate of iron transport as the pH has been increased, but this has also had an impact on the operation of the condensate polishers. Significant differences in the nature and extent of corrosion of air cooled condensers have been observed between base loaded and two shift operation of these plants.

Research, including international collaboration continues to develop a better understanding of the corrosion mechanisms at play, together with strategies to best mitigate the corrosion and ensure design life is achieved.

1. Introduction

Dry cooling Technology is one of the different condensate cooling technologies that Eskom had employed in some of its generating units. The main driver for the implementation of this technology has always been water scarcity problems in most parts of South Africa. Eskom had committed some 10 500 MWe of its generating plant to both direct and indirect cooling system in the past two decades This was done at Kendal (indirect dry cooling), Matimba and half of Majuba power plants (direct dry cooling)

Eskom's Matimba power plant is the biggest dry cooling station (6 x 650 MWe) in the Southern Hemisphere. The first unit at Matimba was commissioned in 1987 and the last unit went into commercial operation in 1991. This plant is near the little town of Lephalale (formally known as Ellisras) in the Limpopo province of South Africa.

The units at Matimba are each served by a forced draught direct air – cooled condensers (ACC) that have been designed and supplied by GEA Air Cooled Systems. At the time of design and construction, the Matimba air cooled condensor plant was ten times larger per generating unit than any contemporary direct air- cooled condensor.
This station was designed to consume 0.4 litres of water per KWh, however due to the implementation of enhancements in the water management system an average specific water consumption of 0.12 l/KWh has been achieved over the years. This represent a saving of over 40% of the total station designed water usage, thus making it more possible for the country to utilise the available water to provide for the basic needs of its population rather than to evaporate large quantise of its water into the atmosphere.

1.1 Direct air-cooled condenser plant description

Direct air-cooled condensers condense the turbine exhaust steam using finned tubes as heat exchangers. Steam flows inside the tubes while the ambient cooling air is forced to flow around the outside and between the fins of the finned tubes. The air removes heat to condense the steam. The condenser plant is designed to remove only the latent heat to obtain condensation of the steam. Due to the dependence on ambient air as cooling medium, a large range of turbine exhaust steam pressure and condensate temperatures occur as the temperature follows the ambient conditions and condensate temperatures of 80˚C are not uncommon in summer. The photo's below outlines a typical GEA ACC design as at Matimba:

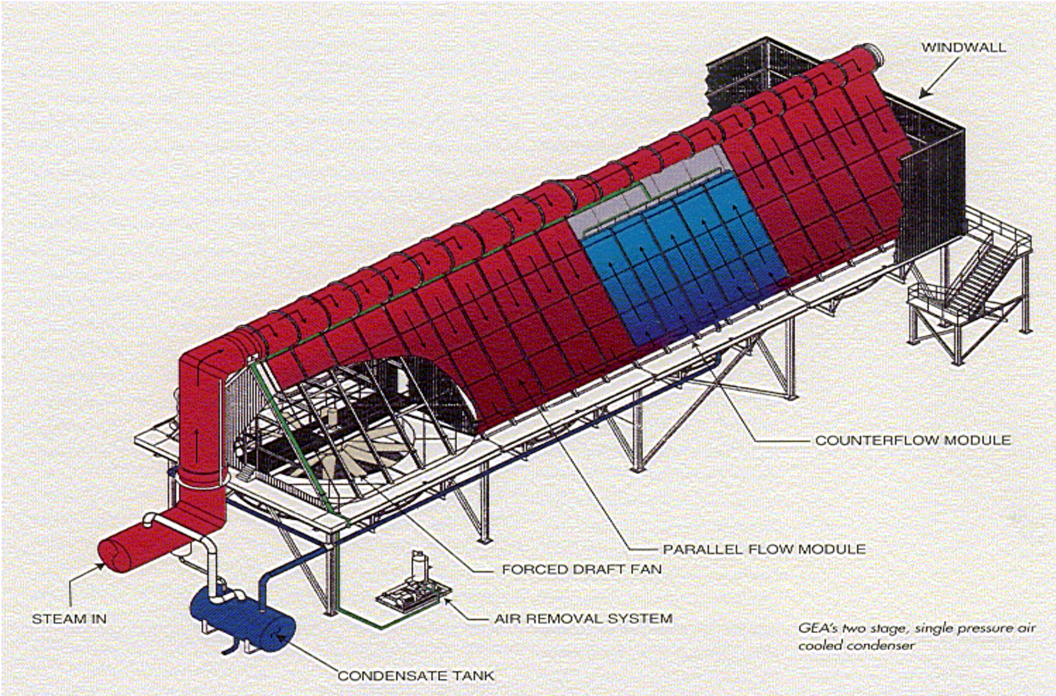

Figure1: General arrangement of a typical ACC (Courtesy GEA air cooled systems)

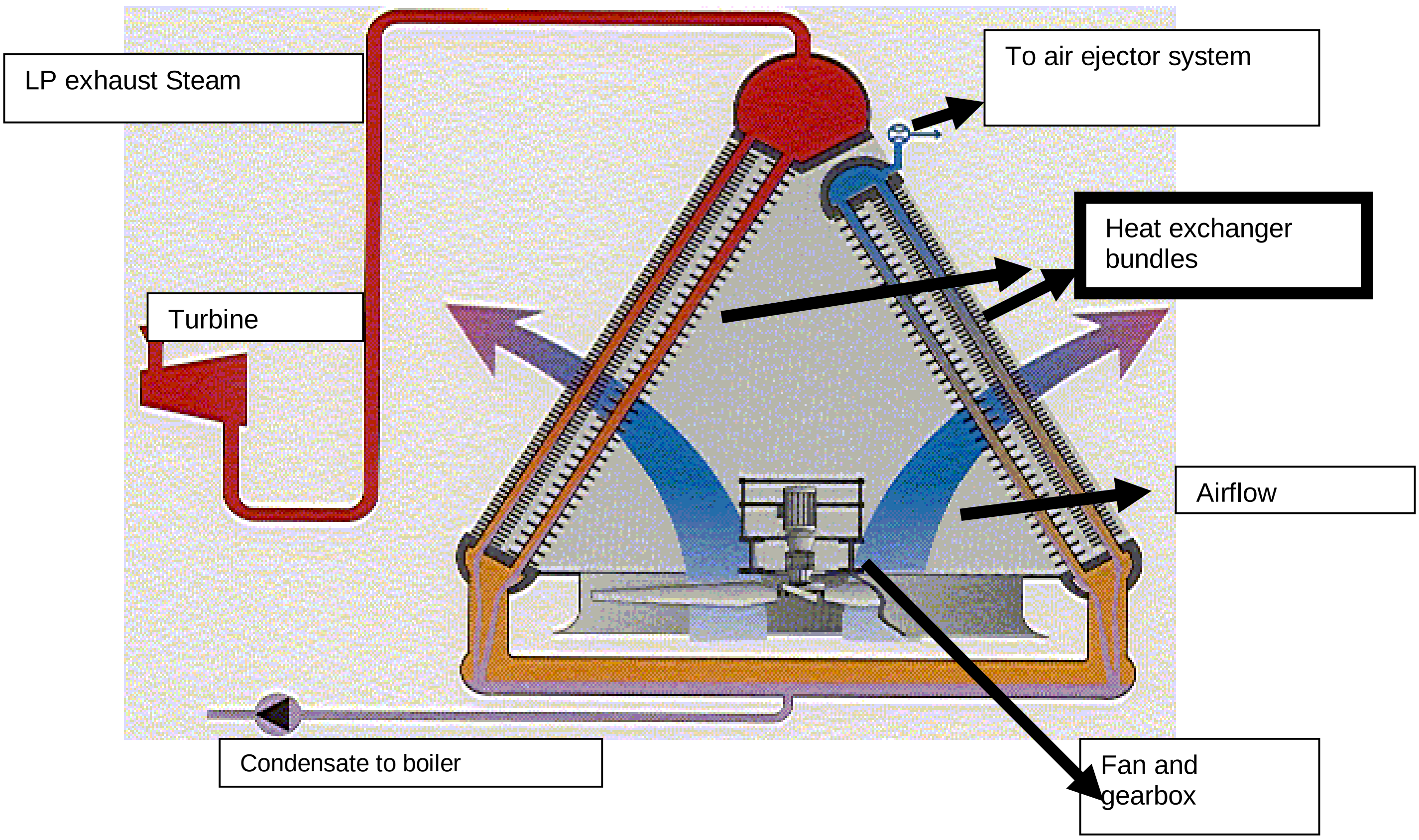

Figure 2: Sectional view of a GEA ACC module showing both K and D type bundles (Courtesy GEA air cooled systems)

1.2 History about changes in the unit chemistry treatment regime

The station was commissioned under All Volatile Treatment, AVT(R) with condensate pH ranging from 9.2 -9.4 during the first few years after commissioning. A decision was taken to increase the steam water cycle pH to 9.7 in the late nineties to help assist with reduction of severe corrosion that was seen in the ACC ducts. Due to problems experienced in early 2000 with condensate polishing plant resin cross contamination and early chloride leakages when the CPP resins are at the end of life, the steam cycle pH was controlled between 9.4 – 9.6 to help minimise the chloride leakage from the CPP. No inspection of the ACC ducts prior to the change in order to assess the extent of corrosion was done. The pH conditions at the time are as illustrated in figure 3 below.

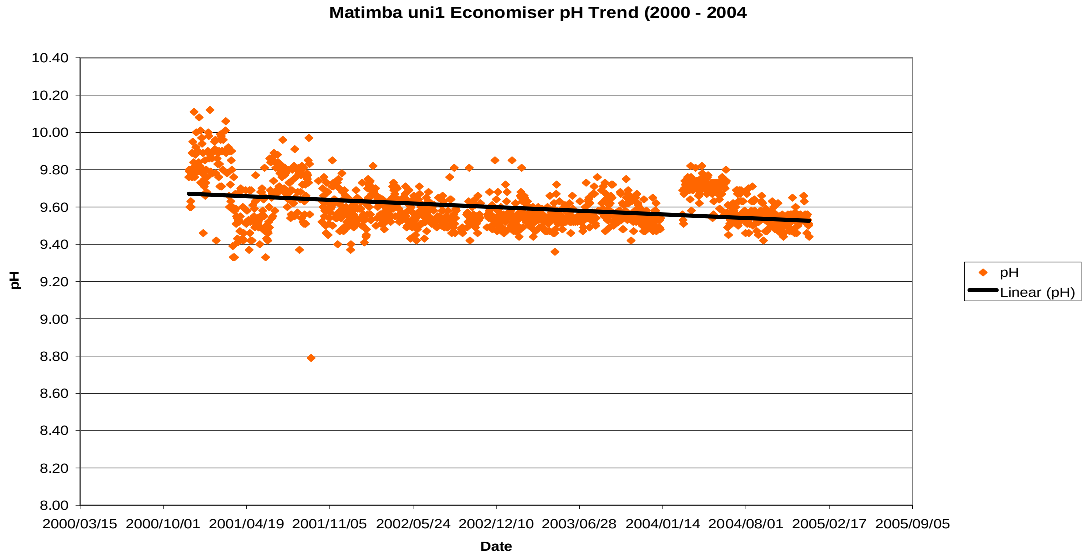

Figure 3: Matimba unit 1 pH trend (200 -2004)

2. Corrosion in the Matimba Air Cooled Condensors

Inspections of the Matimba air cooled condensors during outages revealed that there was corrosion taking place inside the ACC ducts and the fin tube. The exact damage mechanism is not fully understood and at the time when the corrosion was first observed, a number of actions have been identified to obtain more information to try understanding and helping mitigate this corrosion mechanism.
The inspection results shown below were generally observed and recorded on different units and over a period of time since the early nineties since these corrosion mechanisms were first observed.

There were three distinctly different corrosion/erosion mechanisms that were found to be active in the Matimba air cooled condensers.
The first is a corrosion/erosion mechanism active on any surface exposed to the high velocity steam in the top distribution duct. Since the steam is wet (i.e. 5% moisture) the small water droplets entrained in the steam will

erode/corrode the surface as shown in figure 4 below. The steam velocities in the Matimba ACC ducts vary between 35 m/s and 116 m/s at the minimum and maximum ambient design temperature and 80 m/s at the design point. This mechanism was found to be generic to Majuba ACC as well.

Figure 4. Unit 3 inlet seal weld erosion

The second mechanism was found to be active in areas exposed to high volumes of the liquid phase of the exhaust steam. The LP turbine exhaust steam contains 5.4% liquid (moisture) which is separated from the steam by centrifugal forces in areas where the steam direction changes, e.g. around bends. One such a position is where the steam direction changes through 90 degrees at the point where it enters the horizontal distribution duct at the top of the fin tubes. The liquid is thrown against the top surface of the circular duct from where it gravitates along the duct wall towards the bottom of the duct in the direction of the steam flow. This flow pattern is clearly indicated in Figure 5 below.

Figure 5: Unit 3 steam distribution header.

This liquid collects in a trough which is formed between the duct wall and a structural angle profile welded onto the duct wall immediately above the top of the tubes. This condensate is drained from the trough through a series of small openings from where the liquid will find its way into the finned tubes as shown in figure 6 below.

Figure 6, Unit 3 drain flow marks with associated corroded areas at the tube inlets.

Almost without exception it was in areas like these where the second mechanism was active preventing any passive corrosion layer to develop on the steel surface. This is well illustrated in figure 6 by the grey patches visible in the 4 tube ends below the opening in the trough. Based on a visual inspection these grey patches are bare metal surfaces without any protective corrosion layer. A tube was removed from unit 3 for analysis. The results of the analysis are documented in a separate report but in summary confirmed that the grey patches were corroded areas with no oxide deposits. The corroded areas were found over a distance of about 2 meters down the tube measured from the inlet end of the tube. The average wall loss associated with the corroded areas is very small, in the order of 0.1 mm. The only exception to this was a small area immediately below the inlet seal weld where a through- wall pit was visible as shown in figure 7.

Figure 7, Through -wall pit observed on unit 3.

Visual observations suggest that the second corrosion/erosion mechanism was always characterised by the following:

- Always active in areas of relative high volume flows of the liquid phase.
- Found on the inner surfaces of the tube but always on the tube side shaded from the main steam flow in the distribution duct, i.e. best visible if viewed from a downstream direction.
- Found in areas of highly disturbed flow like at the inlet of the tube where the steam entering the tube mixes with the high volume liquid flow as illustrated in figure 6. In areas like this highly turbulent flow is expected especially on the upstream side of the tube surface where a separated flow region is expected.
- Found in areas associated with high flow velocities. Note in figure 3 that the liquid gravitating down the tube sheet did not expose the tube sheet material with a relatively thick soft corrosion product covering the tube sheet. The liquid velocity in this area is low but will be accelerated by the steam as it enters the top end of the tube.

The third and perhaps less important mechanism was found on bodies directly exposed to the steam flow like the stiffeners shown in figure 5. Although the appearance of the third mechanism is similar to that of the second, it differed in the sense that in this case the eroded surface is directly exposed to the approaching steam and not subject to a high liquid flow.

Figure 8. Eroded areas on stiffeners.

The confusing part was the obvious difference between the observation made on this corrosion mechanism as observed at Matimba and Majuba. A photograph below was taken on Majuba unit 1 ACC. In this case no internal tube erosion was found and the entire internal ACC surface, apart from the tube inlets, was found covered with a healthy red iron oxide layer of Heamatite. Majuba unit one is one of the Majuba units which was not two shifting due to limited starts on the generator and should therefore be comparable to Matimba.

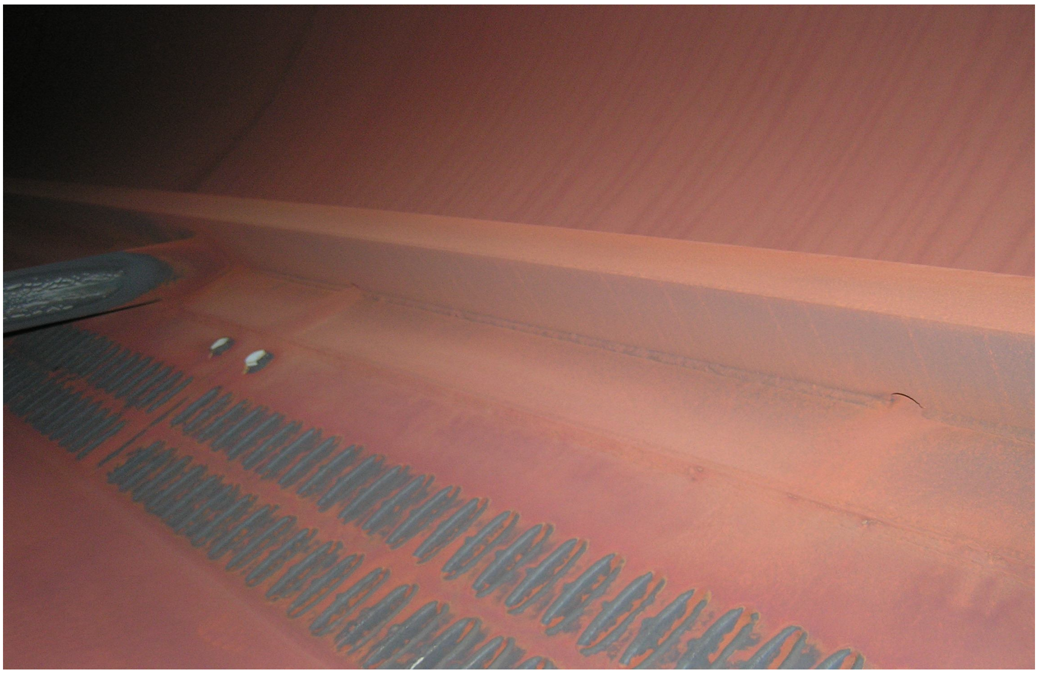

Figure 9. Majuba unit 1 Acc duct condition

3. Measures taken to correct the corrosion problems at Matimba

The actions that have been implemented include; raising of the feedwater pH above 9.5, application of the epoxy coatings of the inlets of the finned tubes as well as extraction of the condensate for chemical analysis.

3.1 Corrosion mechanisms 1 and 3

Corrosion mechanisms 1 and 3 were corrected by application of epoxy wear coat paint on to the inlet seal welds and upper 100 mm of the fin tubes during outages. Painting of the weld seams started in 1995 and continued as per outage program for the six units. It was only done on the first 10 to 20 meters downstream of the dephlegmator and in the first 8 or ten tubes. Although the paint appeared to be effective in protecting the welds from erosion it is however very difficult to apply as it has a very high viscosity and dries quickly once mixed. We also could not do any surface preparation as the debris could not be recovered from the system except by cutting open the bottom headers. Nevertheless the paint seemed to adhere successfully at the surface even without surface preparation.

This treatment was done as per inspection in areas of concern. The experience with the epoxy wear coat was found to be favourable and very little deterioration of the coating and the painted areas was observed between outages.

Figure 10: Matimba ACC Tube welds after painted with epoxy paint.

3.2 Corrosion Mechanisms 2

Based on the condensate drainage marks shown in figure 3, it was decided to install a sample point in that location to drain off and be able to analyse a sample of the initial condensate in the steam distribution duct. A drain line was fitted on one of the steam distribution ducts of unit 1. This sample pH and ionic impurity concentrations were analysed and compared to that of the condensate at the inlet of the CPP. The pH and chlorides results are as on figure 11 and 12 below..

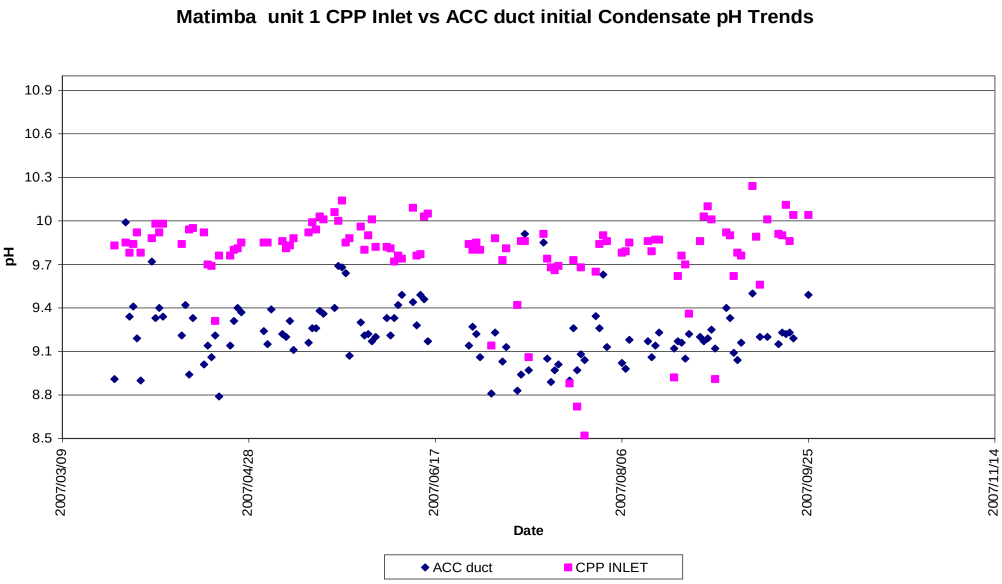

Figure 11: pH of condensate collected from the ACC duct and CPP inlet on unit 1. (Nov 2007)

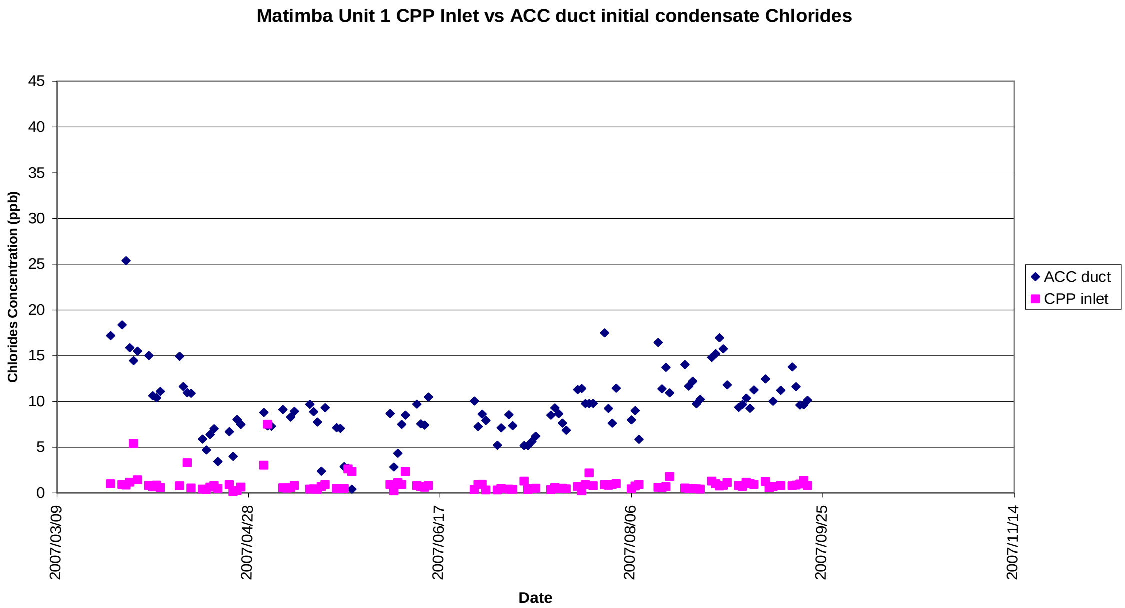

Figure 12: Chlorides concentration of the initial condensate from the ACC duct and CPP inlet on unit 1 (Nov 2007)

Between 2006 and current the steam pH was raised and maintained at 9.6 – 9.8 as on Figure 13.

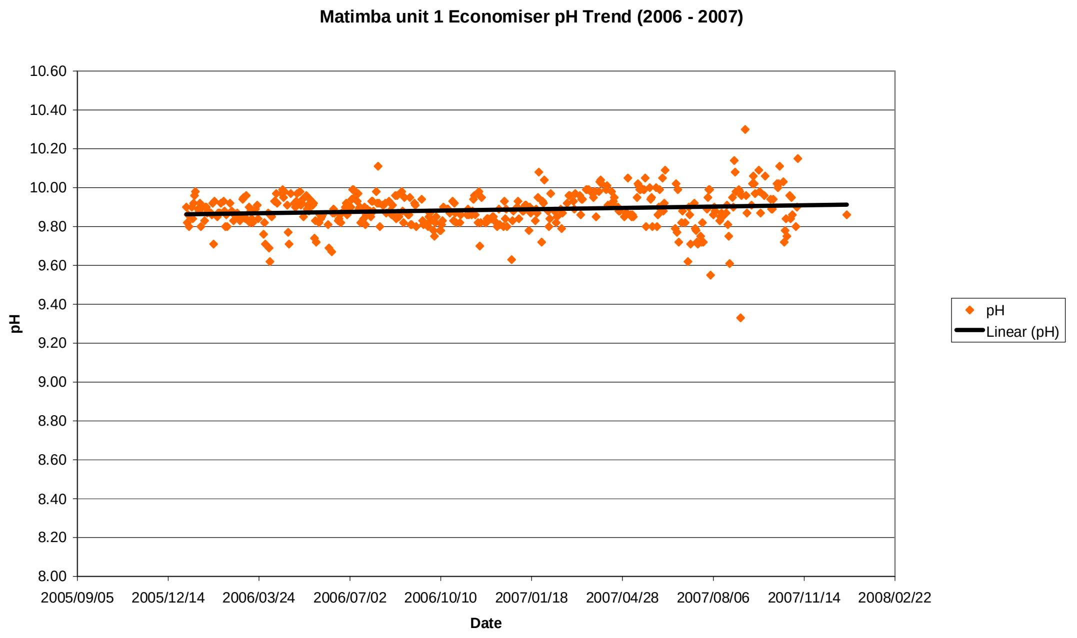

Figure 13: Matimba unit 1 Economiser pH trend (2006 – 2007)

Unit 1 was inspected during Nov 2007 and results shown in figure 9 below. This photo was taken on unit 1 in a similar location as that in figure 3.

Figure 14. No corrosive products from drain hole. Some bare metal patches still remain in tube inlet.

Discussions of the results

By applying the epoxy wear coat paint on the inlet seal welds, any additional metal loss during operation was found to have been prevented as observed during the subsequent plant outages in the areas that were previously painted.
The pH values as shown on figure 8, show a definite reduction in the duct sample pH of around half a pH unit and bearing in mind that the pH is a log value, it is a significant reduction in the buffering capacity in that water. This means that if the CPP inlet pH is controlled up to maximum 9.5, the pH in the ACC duct might be anything below 9.0 thus providing reduced protection to corrosion in the duct. The ACC duct inspections during plant outages as well as draining and testing of the initial condensate from the duct has helped to understand the quality of the initial condensate that is formed in the ACC

4. Current Studies and Future work

Regular inspection of the plant remains important to find and treat localised areas of corrosion where water accumulates in sufficient quantities to flow as a partially “pH depleted” stream into the tubes.
Consideration was given to find and test methods of removing condensate from the heat exchanger steam ducts, however with the diminished amount of erosion currently occurring, it is more economical to closely monitor the plant and take focussed corrective actions than to try and eliminate condensate from the ducts.
Tube inserts that were installed to act as protection as well as grating to guide steam flow at the tube inlets will continue to be monitored. Target plates are also installed at strategic areas to monitor the rate of metal loss at the tube inlets.
Sampling of condensate pH at different stages of the process are planned to obtain a better understanding of two phase flow chemistry

5. Conclusion

The implementation of the corrective actions to address the corrosion problems as observed in the Matimba ACC has produced positive results up to now. Changing and maintaining the condensate feedwater pH above 9.6 has helped considerably in reducing the corrosion as there is an improvement of the internal surface of the ACC ducts as observed in the last two inspections at Matimba unit 1 and 3. Coating with wear resistant paint has proven to be successful in protecting the tube welds against erosion, provided that it is done properly and at a frequency of around 2 years.

6. Acknowledgements

The authors wish to acknowledge the assistance provided by colleagues at Matimba power station for performing all the chemical analysis for this investigation

7. References

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