

Assessing and Controlling Corrosion in Air-Cooled Condensers

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ABSTRACT

An increasing number of air-cooled condensers (ACC) are being installed and operated on conventional and combined cycle plants worldwide. Unless understood and corrected, the corrosion associated with the ACC ducts and tube entries can become a major problem for operators of plant. Up to just a few years ago very little was known about the corrosion/ flow-accelerated corrosion (FAC) process. This paper starts to rectify the situation with a description of the corrosion/FAC process, a corrosion index and a relationship between the operating pH and the level of iron at the condensate pump discharge.

INTRODUCTION

Since the installation of the first small 1 MW dry cooling system in 1939, many hundreds of air-cooled condensers (ACC) have been erected worldwide. Corrosion of the carbon steel components in these large systems has been a concern because of the impact of high iron levels and air in-leakage [1]. The maximum corrosion has been observed at the entries to the A-frame ACC tubes. The mechanism of this corrosion is not fully understood and little work has been expended in trying to rectify this. As far as the authors know, only two ACC tubes have been removed for metallurgical examination. Based on these two analyses the actual corrosion appears to be a flow-accelerated corrosion (FAC) derivative where local indigenous magnetite is removed from the surface of the ACC tube leaving a very intergranular surface appearance. Adjacent to these areas where the local turbulence of the two-phase media is not as great, the magnetite deposits on the surface. There are clear boundaries between the regions where corrosion/FAC takes place (white bare metal) and regions where deposition (black areas) occurs.

Figure 1 shows one of the two ACC tubes which have been subjected to a metallurgical analysis. The low magnification photograph of the surface of the ACC tube near to the tube entry clearly shows the adjacent black and white areas. The other two parts of the figure show details of the black areas, which are essentially deposited magnetite (upper part, left), and the white bare metal area, which has an intergranular appearance (upper part, right).

These metallurgical analyses have provided the first detailed investigations of the interfacial science taking place between the fluid and the ACC duct and tube surfaces. It is anticipated that more tubes will become available to assist in the development of a fuller understanding of the corrosion and deposition mechanisms. However, in the interim operators of ACC need guidance in operation so that the corrosion/FAC can be minimized. This paper

describes two major steps which have been taken over the last few years to quantify ACC damage: a) an index to assess the severity of the corrosion/FAC process throughout the ACC system from the steam turbine exhaust to the collected condensate, and b) a relationship between the cycle chemistry (pH) and the level of corrosion/FAC.

A parallel paper [2] outlines an interim cycle chemistry guidance for ACCs developed for EPRI.

ACC CORROSION INDEX

After inspecting a number of ACCs around the world, two of the authors developed an index for quantitatively defining the internal corrosion status of an ACC. This is known by the acronym DHACI (**D**ooley **H**owell **A**CC **C**orrosion Index) [3,4]. The index separately describes the lower and upper sections of the ACC, according to the following:

Upper Section (upper duct/header, ACC A-frame tube entries). Index: 1, 2, 3, 4 or 5. Examples are shown in Figure 2.

1. Tube entries in relatively good shape; possibly some areas with dark deposits in first few inches of tube interior. No corrosion or FAC.
2. Various black/grey deposits on tube entries as well as flash rust areas, but no white bare metal areas. Minimal corrosion/FAC.
3. Few white bare metal areas on a number of tube entries. Some black areas of deposit. Mild corrosion/FAC.
4. Serious white (bare metal) areas on/at numerous tube entries. Extensive areas of black deposition adjacent to white areas within tubes. Serious corrosion/FAC.
5. Most serious. Holes in the tubing or welding. Obvious corrosion on many tube entries.

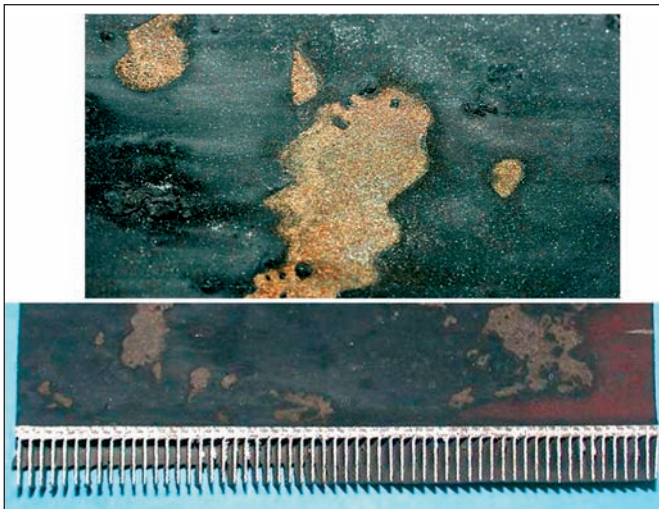
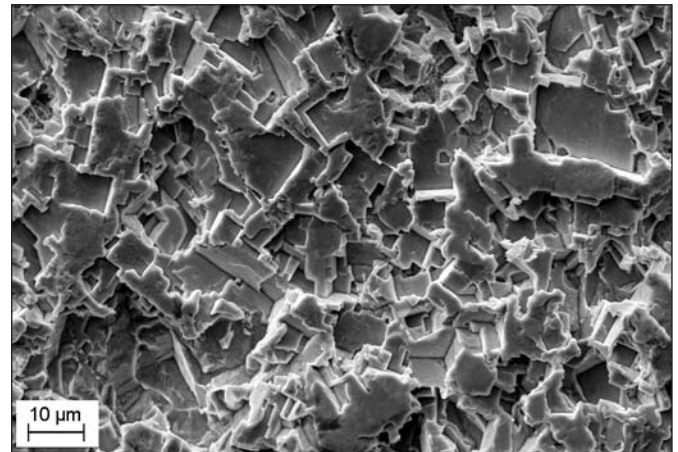
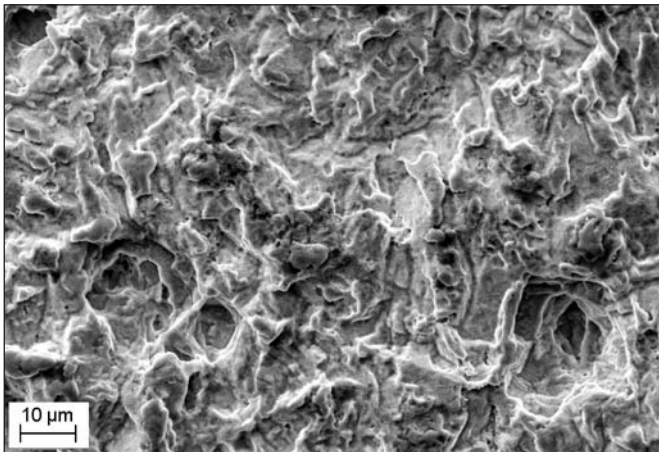


Figure 1:

Details from the examination of an ACC tube section within about 38 cm (15 in) from the tube entry in the upper duct. The lower photograph shows the adjacent white and black areas on the tube surface. The two upper parts of the figure show surface metallographs of the black area after cleaning of the surface (left) and white bare metal (right).

Lower Section (turbine exhaust, lower distribution duct, risers); rate A, B or C. Examples are shown in [Figure 3](#).

- Ducts have no indication of damage and are grey in color.
- Minor white (bare metal) areas on generally grey ducts. Some 'tiger striping' appearance with darker grey/black areas demonstrating two-phase flow-accelerated damage. Overall assessment is 'mild damage'.
- Multiple, widespread areas of bare metal in the turbine exhaust and at abrupt changes in flow direction (e.g. where steam flow enters vertical riser from lower distribution duct). White (bare metal) areas are evident indicators of metal loss. Severe local damage exists.

The index provides a number (from 1 to 5) and a letter (from A to C) to describe/rank an ACC following an inspection. For example, an Index of 3C would indicate mild corrosion at the tube entries, but extensive corrosion in the lower ducts.

The DHACI can be used to describe the status of a particular ACC in terms of its corrosion history. A poor rating (e.g. 4B) indicates the need to consider options to reduce the corrosion rate, especially in the tube entry areas.

Additionally, the index provides a convenient tool for comparison between different units. This can aid in determining whether some factor in effect at one station, e.g. use of an amine rather than ammonia, is yielding better results.

Finally, the DHACI is a very useful means of tracking changes that occur as a result of making changes in steam cycle chemistry. A plant that has a relatively poor rating for corrosion at a steam cycle pH of 8.5–8.8 (e.g. 4C) may increase the pH to 9.4–9.6 and determine whether this change improves its rating (e.g. 3B). Similar tracking may be done in association with mechanical or material changes, or with major shifts in operating pattern (cycling vs. baseload operation).

DEVELOPMENT OF RELATIONSHIP BETWEEN pH AND CORROSION IN ACC AND THE RAMIFICATIONS FOR CONDENSATE POLISHING SYSTEMS AND THE USE OF AMINES

The current understanding of the mechanism associated with the corrosion of ACCs has been outlined in the introduction. Regardless of the mechanism itself both chemistry data and visual evidence suggest that the pH

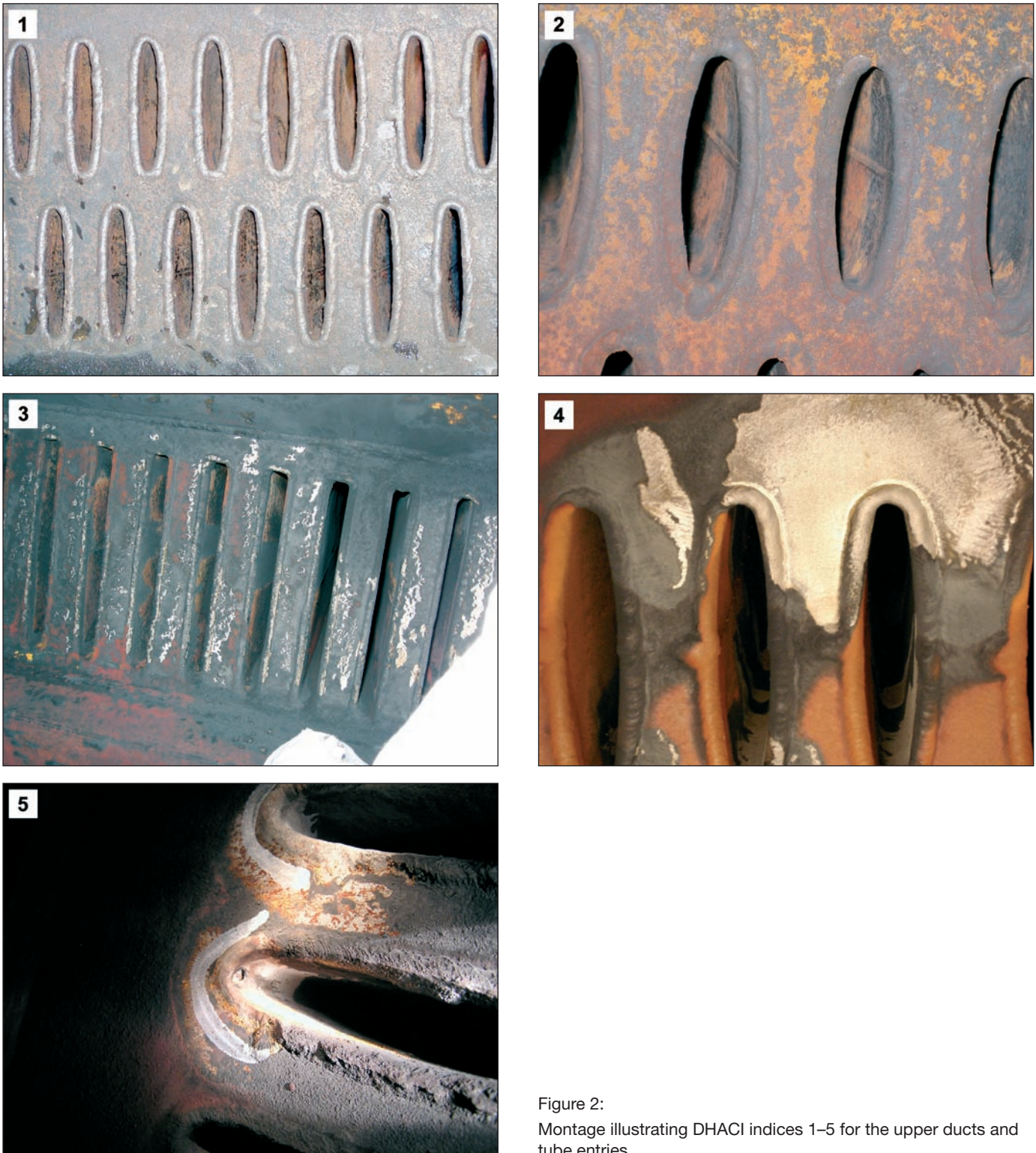


Figure 2:
Montage illustrating DHACI indices 1–5 for the upper ducts and tube entries.

environment plays a significant role in the corrosion process. Currently data is only available from organizations which employ ammonia as the feedwater conditioning chemical for pH control. It has also been discussed that the two-phase conditions present in the upper ducting of the ACC are likely to contribute to the corrosion process at the tube entries.

In two-phase conditions ammonia much prefers the vapour phase over the liquid phase. Therefore in the liquid droplets, associated with the first condensate, that come into contact with the ducts and condensing tube inlets there is far less ammonia present than that originally injected into the condensate/feedwater of the plant. Note also that some of the ammonia vapour will be removed in the dephlegmator of the ACC. As a result, where these

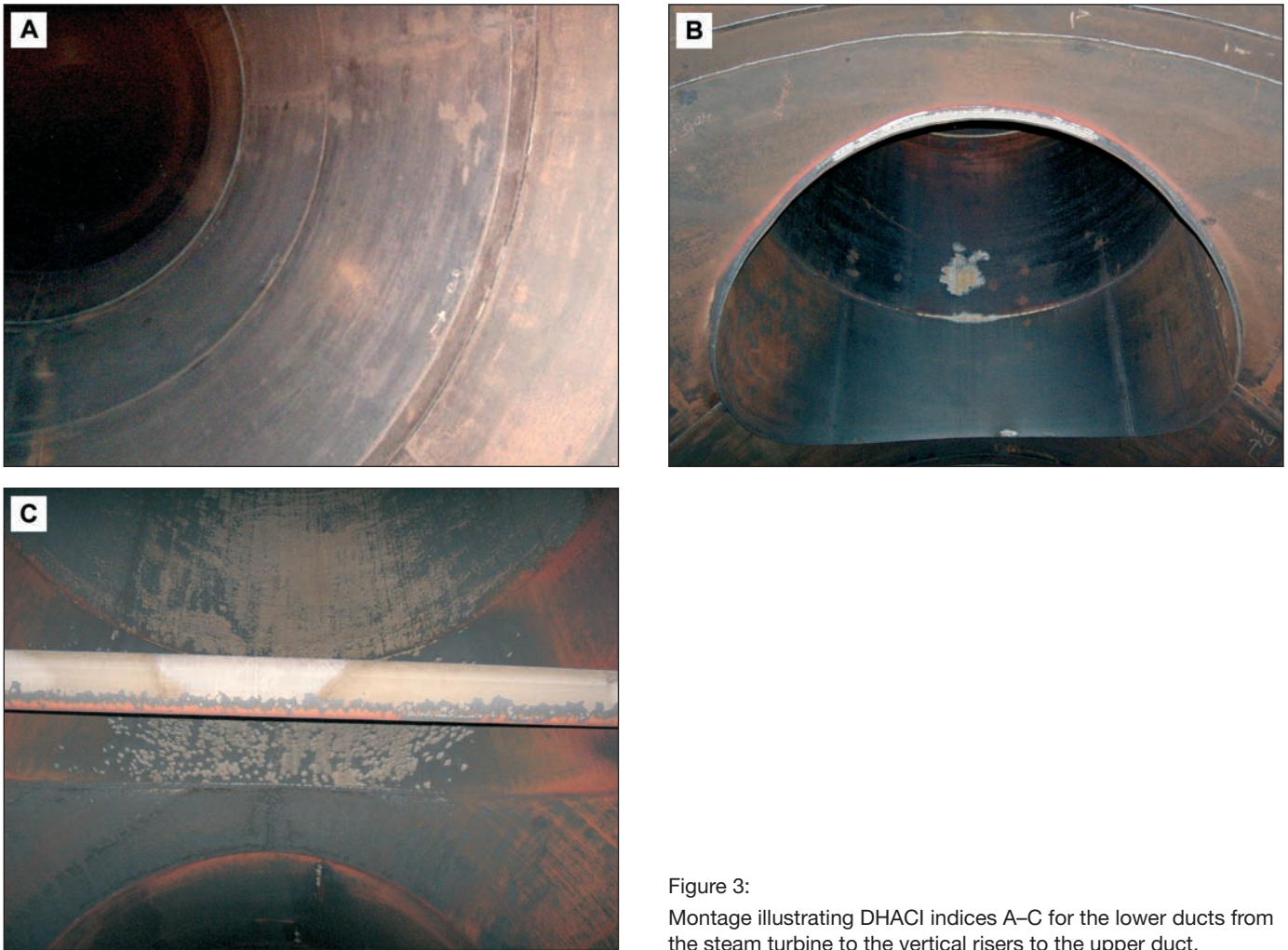


Figure 3:

Montage illustrating DHACI indices A–C for the lower ducts from the steam turbine to the vertical risers to the upper duct.

liquid droplets come into contact with the ducts, in particular the tube entries, the solution pH can be as much as 1 pH unit lower than the condensate/feedwater pH at 25 °C (77 °F). This has been confirmed by measurement [5]. More importantly the differential between the solution pH and the neutral pH (at temperature) is significantly reduced. With this reduction in alkalinity and under the influence of locally increased turbulence, iron oxide (magnetite) dissolution is increased.

Increasing the ammonia concentration in the condensate/feedwater of the plant will increase the first condensate pH of the droplets and thus reduce the oxide solubility. However, because of the effect of the reducing basicity of ammonia with increasing temperature and the preferential vapour phase distribution of ammonia, a great deal more ammonia has to be added.

Data gathered from several organizations around the world has resulted in the development of the Dooley/Aspden relationship for Fe in the condensate at the condensate pump and pH associated with units having ACC [3]. This is illustrated in Figure 4, which also shows the corresponding curve for magnetite solubility extracted from Sturla's mag-

netite solubility data [6] at 50 °C (120 °F). The steam/condensate temperature throughout the ACC is for all practical purposes constant since the ACC only rejects the latent heat in the exhaust steam. The steam temperature depends on the ambient temperature and the design of the ACC. The minimum and maximum design steam temperatures, and thus the steam temperature at the tube entries, are usually between 45 and 80 °C. So the 50 °C used in Figure 4 is near the lower end of the scale, but the solubility of magnetite varies very little up to 80 °C.

The band in Figure 4 is about $5 \mu\text{g} \cdot \text{kg}^{-1}$ wide to allow for uncertainty associated with the data from many organizations, but does have a strong track record around the world for units with ACCs using only ammonia conditioning for pH control. The relationship shows that these plants require a condensate/feedwater pH of at least 9.8 to achieve acceptably low iron levels at the condensate pump discharge. Alternatively, operating at the normal pH range associated with normal oxygenated treatment of between 8.0 to 9.0 would be absolutely disastrous for the ACC as has been illustrated [7,8]; high levels of corrosion will ensue at the tube entries and failures in the ACC can be expected. The high levels of iron will also completely over-

whelm the filtration capability of condensate polishers (where fitted) resulting in short resin runs due to differential pressure limits and significant deposition in boiler or HRSG tubes.

Figure 4 also shows the solubility of magnetite extracted from Sturla [6] at the approximate temperature of the tube entries of an ACC (50 °C (120 °F)). The practical corrosion curve in the figure is elevated above this normally accepted magnetite solubility relationship by some considerable amount and shows for instance that at pH of 8.8 the ACC relationship is higher by 40–50 $\mu\text{g} \cdot \text{kg}^{-1}$ and at pH of 9.2 it is higher by about 30 $\mu\text{g} \cdot \text{kg}^{-1}$. Only at pH of 9.8 and above do the curves become convergent. This suggests that the corrosion process at the lower pH range is faster or more aggressive than a normal classical two-phase FAC process [9] which may relate to the severe turbulence created by the tube entries.

From the parallel field of nuclear plant two-phase FAC, Table 1 illustrates the calculated effect of the different regimes on the liquid film pH under conditions approximating those of the condensate droplets in the ACC ducting.

What is evident from the table is that when a plant is using conventional oxygenated treatment (OT) at pH 8.5 the delta pH, the pH at solution temperature – neutral pH (last column), is only 0.26. It has been established by workers in the nuclear industry that a minimum delta pH of 1 unit (at solution temperature) is required to mitigate two-phase FAC. The table shows that to achieve this, the condensate/feedwater pH needs to be close to 9.8, which supports the Dooley/Aspden relationship shown in Figure 4.

CONDENSATE POLISHING

Where condensate polishing is fitted, these high levels of ammonia that are required to protect the ACC present a significant challenge. Where polishers are employed they

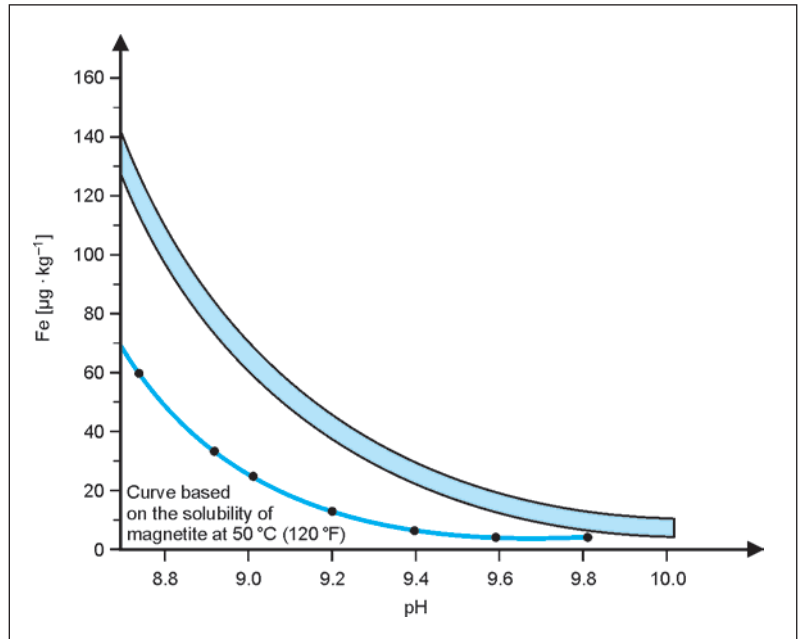


Figure 4: Iron levels measured at condensate pump discharge on units with ACC and only using ammonia for pH control. The iron solubility data which is extracted from Sturla [6] at 50 °C is shown only as an example as actual operating temperatures at the ACC tube entries may be higher, as discussed in the text.

are usually of the deep mixed-bed variety, which are designed for hydrogen form operation. This means that under these high pH conditions the operating cycles will be 2 to 3 days due to ammonium loading. The regeneration turnaround and effluent production make this mode of operation extremely difficult and costly.

Ammonium form operation of mixed beds is an option [11] but presents significant challenges regarding polished water quality at these high pH values.

At least one utility has approached this problem by equipping the ACC units with deep bed polishers using separate cation and anion vessels. This makes ammonium form operation quite simple and the required water quality is readily achieved. Capital costs are higher but the opera-

Treatment regime	Condensate		Ammonia concentration						Liquid phase	
			Condensate		Condensing steam					
	pH (25 °C)	ΔpH^*	$\mu\text{g} \cdot \text{L}^{-1}$	Molal	Liquid phase		Vapour phase		pH (c)	ΔpH^{**}
					$\mu\text{g} \cdot \text{L}^{-1}$	Molal	$\mu\text{g} \cdot \text{L}^{-1}$	Molal		
OT	8.5	1.5	64	$3.765 \cdot 10^{-6}$	0.31	$1.804 \cdot 10^{-8}$	63.7	$3.747 \cdot 10^{-6}$	6.18	0.26
High pH OT	9.8	2.8	5 018	$2.952 \cdot 10^{-4}$	7.02	$4.129 \cdot 10^{-7}$	5 012	$2.948 \cdot 10^{-4}$	7.05	1.13

Table 1: Calculations showing ammonia concentrations and delta pH for early condensate [10].
 pH (25 °C) = pH measured at the reference temperature of 25 °C
 ΔpH^* = difference between pH (25 °C) and the neutral pH (25 °C)
 ΔpH^{**} = difference between pH at temperature and neutral pH at temperature

tional costs are very attractive with cycles of 60 days or more being the norm.

Powdered resin filtration systems also offer some benefits but the limited ion exchange capacity may deter some users, particularly if operation at high pH (ammonium form) is desired.

The use of an amine injected into the crossover steam pipes (superheated steam) between the intermediate pressure (IP) and low pressure (LP) turbines is another avenue which could be considered. A relatively low concentration of an amine such as ethanolamine (ETA) or dimethylamine (DMA) would be required to achieve the required delta pH of > 1 unit ($64 \mu\text{g} \cdot \text{kg}^{-1}$ ammonia for feedwater pH 8.5 and $100 \mu\text{g} \cdot \text{kg}^{-1}$ ETA). This would allow for reasonable and acceptable polishing cycles to be achieved with hydrogen form polishing. The injection of ammonia downstream of the polishers to achieve a feedwater pH of 8.5 would satisfy OT requirements. The removal of all the amine on the polishers would therefore retain the cation conductivity as a core measurement parameter. The authors are not aware of any organization using this technique and it would need to be evaluated to ensure that the correct mixing in superheated steam can be achieved and that the amine will not degrade in the short residence time at IP turbine outlet temperatures around 380°C (716°F). Also, although a number of combined cycle units with ACC are using amines and blends of amines including ETA, there is insufficient data at this time to superimpose another curve on the Dooley/Aspden relationship (Figure 4).

PRACTICAL CASE STUDY OF CORROSION IN AN ACC

Numerous internal inspections have been performed on the ACC ducts at Eskom's Matimba Power Station in

South Africa. The station (Figure 5) consists of 6 coal-fired units with a gross generating capacity of 665 MW each. The first unit at Matimba was commissioned in 1987 and the last unit went into commercial operation in 1991.

The station was commissioned using an all-volatile treatment chemistry, AVT(R). The condensate pH ranged from 9.2–9.4 during the first few years of operation. A decision was made in the late 1990s to increase the steam/water cycle pH to 9.7 to help reduce the severe corrosion that was seen in the ACC ducts. Due to problems experienced in early 2000 with condensate polishing plant (CPP) resin cross contamination and early chloride leakages when the polisher resins were at the end of life, the steam cycle pH was controlled between 9.4–9.6 to help minimize the chloride leakage from the CPP [5].

The Matimba ACC exhaust ducts consist of rather complex arrangements of vertical and horizontal duct sections connected by a series of 90° bends, which in most cases are fitted with guide vanes to minimize the steam side pressure drop. Figures 6 and 7 illustrate the side and front views of the ACC duct arrangement to convey the exhaust steam from the LP turbine exhaust to the condensing elements.

The two LP turbine exhausts are downward facing and the first vertical duct section (only one V1 is shown in Figure 6) is designed as a transition piece from a rectangular to a 5 m (16.4 ft) diameter round steam duct. The first guide vane bend connected to the transition piece diverts the steam in the horizontal direction (H1). After penetrating the turbine house wall another guide vane bend turns the steam direction in the vertical direction. Two vertical risers (only one V2 is shown in Figures 6 and 7) convey the steam upwards to an elevation of 30 m (98.4 ft) above the zero meter level, where the flow is distributed by two horizontal distribution pipes (only one H2 is shown in Figure 7) to 8 risers (4 risers per side) (V3) of 2.5 m (8.2 ft) diameter each,



Figure 5:
Aerial view of the Matimba Power Plant showing the ACC at the front of the power plant.

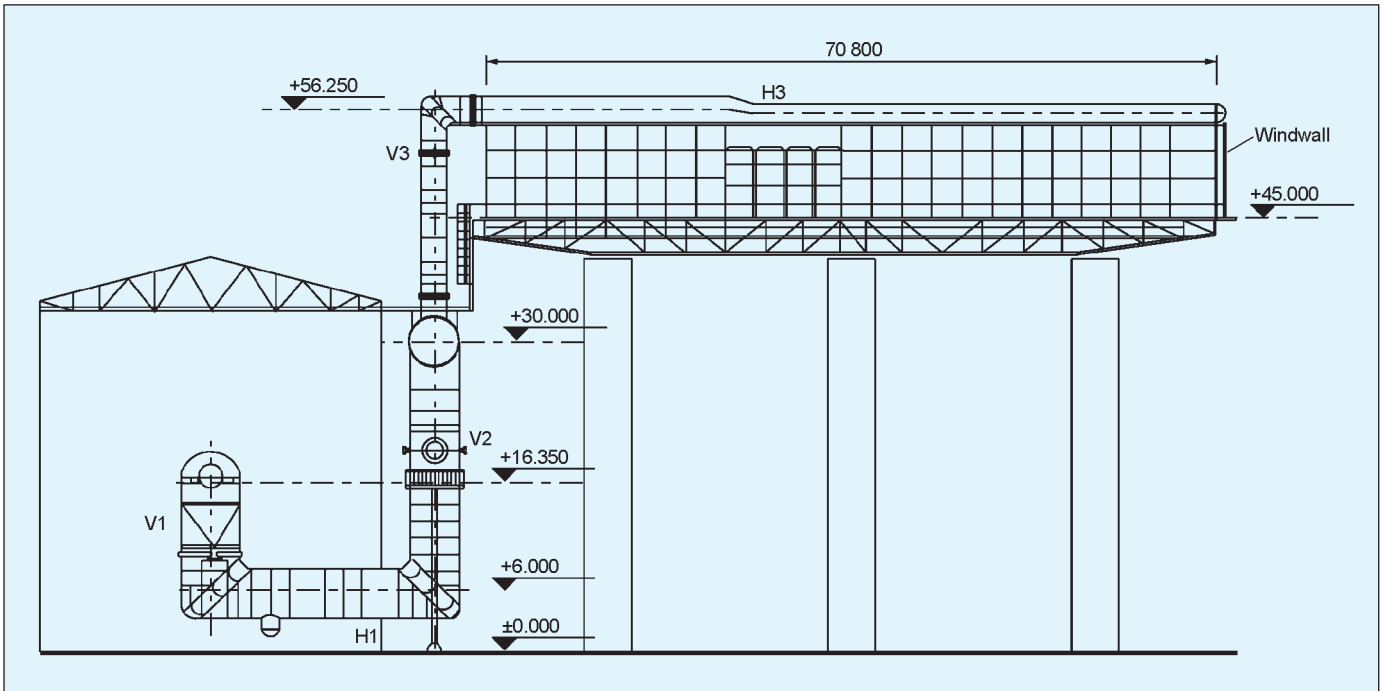


Figure 6:

Side view of the Matimba ACC ducts. Duct V1 takes the two-phase steam mixture from the steam turbine. V1, V2, V3, and H1 are considered to be the lower ducting of the ACC in the DHACI nomenclature. H3 and the ACC tube entries are considered to be the upper sections of the ACC.

which convey the steam to the inlet of the condensing elements (H3) at an elevation of 56 m (184 ft) above the local zero level.

Depending on the ambient temperature, the design LP turbine exhaust pressure (absolute) varies from a minimum value of 11.5 kPa (1.66 psia) at minimum ambient temperature to a maximum value of 46.5 kPa (6.7 psia) in summer. Due to the corresponding variation in the specific volume of the exhaust steam, the average steam velocity in the ducts varies approximately between $35 \text{ m} \cdot \text{s}^{-1}$ and $120 \text{ m} \cdot \text{s}^{-1}$ (114 and 393 $\text{ft} \cdot \text{s}^{-1}$) at the maximum and minimum exhaust pressure respectively. At the weighted annual average exhaust pressure of 19.8 kPa (absolute) (2.87 psia), the average steam velocity is $76 \text{ m} \cdot \text{s}^{-1}$ (249 $\text{ft} \cdot \text{s}^{-1}$) with a moisture content of 5.4 %.

Condensation of the exhaust steam occurs in bundles of finned heat exchanger tubes. The latter is characterized by rectangular fins fitted mechanically on an elliptical tube core as shown in Figure 8. A corrosion resistant bond between the fin root and tube is achieved by hot dipped galvanizing of the fin/tube. Heat exchanger bundles are constructed by arranging two tube rows in the air flow direction (A-frame). 48 axial flow fans per turbine unit of 9.1 m (29.8 ft) diameter each driven by a 270 kW electric motor force ambient air through the finned tubes as cooling medium.

Internal inspections of the Matimba exhaust ducts and steam headers during outages revealed areas with corro-

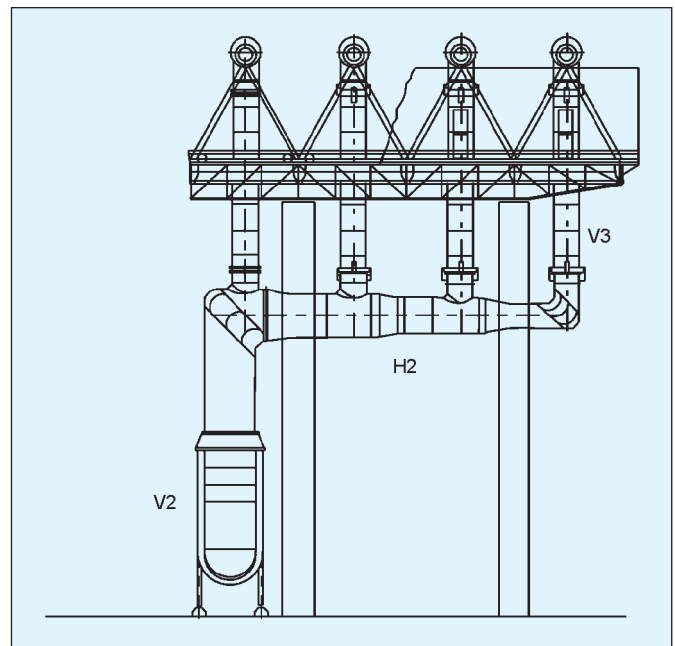


Figure 7:

Front view of the Matimba ACC ducts. H2, V2 and V3 are considered to be the lower ducting of the ACC in the DHACI nomenclature. H3 (above the A-frames) and the ACC tube entries are considered to be the upper sections of the ACC.

sion/FAC and a corresponding loss of material. The exact damage mechanism was not fully understood initially. At the time when the corrosion was first observed, a number of actions were identified to obtain more information for a



Figure 8:
Matimba ACC heat exchanger tube. The tubes are 9.5 m (31.7 ft) long. The rectangular fin dimensions are 120 and 50 mm (4.7 and 1.96 in).

better understanding and to help mitigate the corrosion/FAC mechanism. Among these options, cycle chemistry changes were made as discussed above as well as applying wear resistant protective coatings.

Based on the various internal duct inspections conducted on the different Matimba units, it was evident that the liquid phase in the turbine exhaust steam had a significant effect on the corrosion pattern in the ducts. In areas where liquid accumulates significantly more corrosion was observed compared to areas exposed to dry saturated steam. As a result of the relatively high average steam velocity and the centrifugal forces exerted on the two-phase flow by the guided bends, the free water droplets in the exhaust steam accumulate and become separated from the steam [5].

The DHACI was used as a quantitative measure to define the internal corrosion status of the steam ducts and headers of the ACC. In the following examples the application of the Index is illustrated and used to quantify the benefit that the cycle chemistry changes had on the corrosion status.

Of immediate concern during the initial Matimba inspections was the perforation of the relatively thin wall, 1.5 mm (0.059 in), of the elliptical fin tube at the tube entry. Any perforations would result in an air leak into the vacuum space with an adverse effect on condenser performance. [Figure 9](#) shows a perforation in a tube entry surrounded by a large white corroded area. This white area is the same as the "bare metal areas" described in the introduction and is shown in more detail in [Figure 1](#).

[Figure 10](#) shows patches of white corroded areas in a number of tube entries in a location of high liquid concentration caused by the two drain holes in the channel immediately above the tube entries. These white areas have



Figure 9:
Through-wall penetration of the tube wall immediately below the seal weld at the tube entry. Also note the loss in material of the seal weld. This is recorded as DHACI 5.

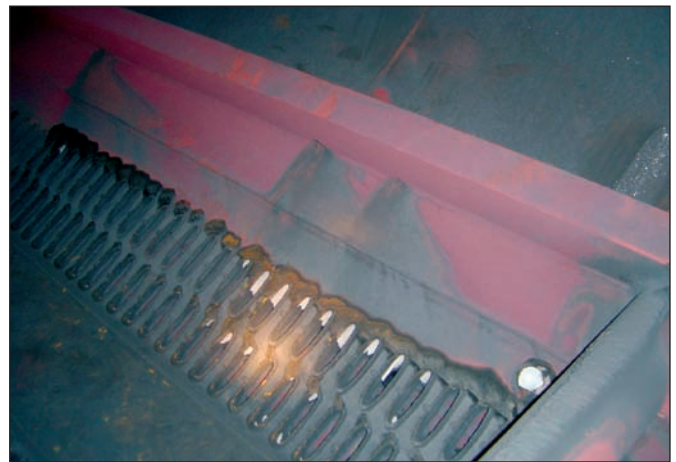


Figure 10:
White bare metal areas at a number of tube entries which are immediately below a drain hole in a channel on the duct surface. This is recorded as DHACI 3.

been described in the introduction and are shown in [Figure 1](#). The surrounding dark grey areas are the same as the black deposited areas also described in relation to [Figure 1](#).

Whilst the desired pH for operation at Matimba Power Station was 9.8 for the protection of the ACC, there was a period of operation when the pH had to be reduced to 9.4 because of problems related to the ability of the condensate polishing plant to operate in the ammonium form. This lasted for approximately two years and the resulting damage to the ACC is evident in [Figures 9 and 10](#). Tube entries, rated at DHACI 1, with no visible white bare metal areas (FAC) are shown in [Figure 11](#), which illustrates the improvement when a plant is operated at a pH of 9.8. Such significant improvements can occur in approximately two years.

Corrosion of the exhaust (lower) ducts should generally not compromise the overall integrity of the ducts or vacuum

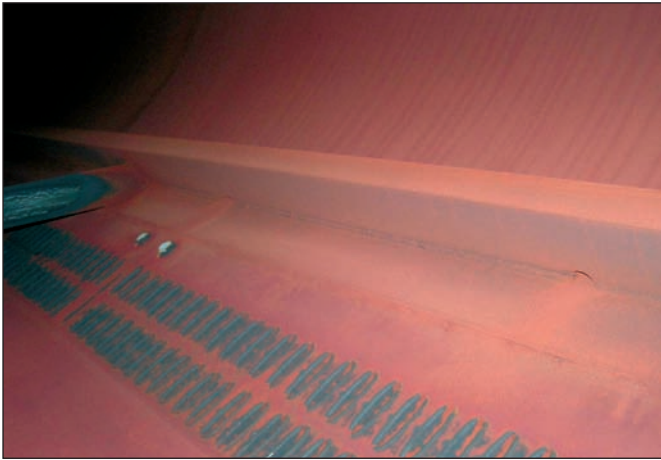


Figure 11:
Well-protected tube entries with no white bare metal areas and a well passivated red duct surface in an ACC operating with a pH between 9.6 and 10. This is recorded as DHACI 1.



Figure 12:
Localized area of significant wall loss in the lower exhaust duct. DHACI C.

boundary of the ACC but will contribute to the iron transport in the condensate. However, in localized areas significant material loss can be experienced, generally in areas of highly disturbed flow or high liquid phase concentration. An example of such an area in the lower ducting, immediately downstream of the trailing edge of a guide vane in a bend, is shown in [Figure 12](#). The figure shows a corroded area where material loss of about 3 mm (0.117 in) is experienced after a total exposure of 146 000 operating hours.

The corrosion in [Figure 12](#) is an exception, and generally minor wall loss is associated with the corroded areas. Such an example is given in [Figure 13](#), which shows some 'tiger striping' appearance with darker grey/black areas demonstrating two-phase flow-accelerated damage.



Figure 13:
Minor bare metal (white) areas on black background as observed in the duct section H1 (see [Figure 6](#)). DHACI B.

A detailed internal ACC duct inspection was performed on Matimba Unit 5 in September 2008. A definite improvement in duct appearance was observed in the steam flow direction, i.e. fewer white bare metal areas were observed with increasing distance from the LP turbine exhaust flange. In [Table 2](#), a qualitative comparison is shown

between the appearances of the different duct sections as identified in [Figures 6 and 7](#). The improvement (lower corrosion/FAC areas) was due to the return to pH 9.8 and the associated "self repair" which took place.

Duct section (Figures 6 and 7)	% red area	% black area	% bare metal (white)
V1	0	95	5
H1	40	50	10*
V2	60	40	< 1
H2	70	30	< 1
V3	75	25	< 1
H3	85	15	< 1

Table 2:
Duct appearance of Unit 5.

* The majority of the bare metal areas are caused by the LP bypass dump diffusers which are located inside duct section H1.

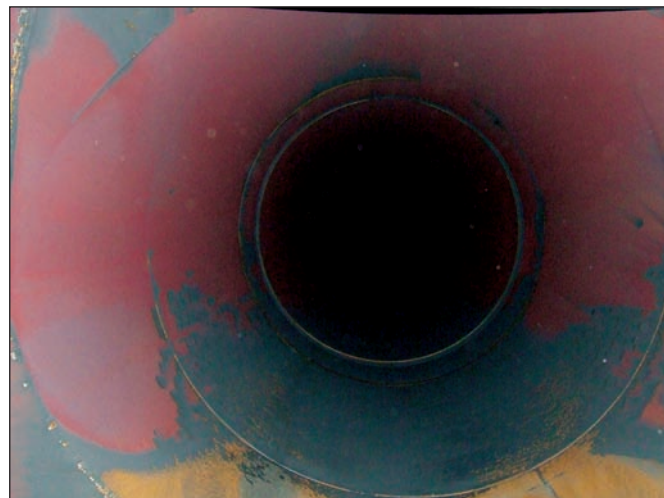


Figure 14:
Corrosion pattern in branch H2-V3 (Figure 7). DHACI C.

The effect of the moisture content in the exhaust steam is well illustrated in Figure 14, which shows the branch H2-V3. On the downstream side of the branch a large bare metal area is visible with patches of flash rust, while the rest of the branch circumference is well protected with a stable oxide layer. Due to centrifugal action the free moisture in the exhaust steam impinges on the downstream side of the branch, resulting in the corrosion pattern shown in the figure.

CONCLUDING REMARKS

By examination of only two tubes worldwide the authors have started to understand the corrosion processes in ACCs. Based on this it has been possible to develop two tools for operators to use in assessing the condition of ACCs. The first, a corrosion index, DHACI, allows the operators to assess corrosion/FAC on a common basis and to monitor changes in corrosion as a result of chemistry or coating changes. The second, the Dooley/Aspden relationship between corrosion/FAC and pH in the cycle, clearly shows the importance of pH adjustment in optimizing the iron levels in the cycle.



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Abraham Francois du Preez (Ph.D., Mechanical Engineering, University of Stellenbosch, South Africa) joined Eskom, the electric power utility in South Africa, in 1994, where he has gained maintenance and operational experience on dry cooling systems, including air-cooled condensers. As the responsible engineer he provides design, operational and maintenance technical advisory and support service to power stations for condensers and cooling systems. His recent work includes the specification for the air-cooled condensers for the 6x800 MW Medupi power station, which is currently under construction.

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