

# **ON-LINE MONITORING AND CONTROL OF FURNACE WALL CORROSION IN PF-FIRED BOILERS**

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## **ABSTRACT**

Coal remains the most economical and widely available fossil fuel for the base-load generation of electricity within the western world. However, with today's competitive environment for the generation of electrical power and the longer-term requirement to minimise the production of greenhouse gases, operators are increasingly trying to maximise the efficiency of pulverised fuel (PF) fired boilers. This is being achieved in a number of ways, including increasing the interval between scheduled maintenance shutdowns and operating the boilers under optimum conditions by careful control of combustion parameters. For example, Drax power station, with a 4000MW output (equivalent to 10% of the UK base-load), has increased the interval between major shutdowns from 4 to 6 years and hopes to extend this even further in the future. Efforts are also being directed towards improvements to combustion conditions, including minimising excess oxygen levels and optimising tube-cleaning procedures.

Corrosion, fouling and sometimes failure of the heat-exchanger tubing that makes up the boiler walls is a major obstacle to minimising boiler downtime. Until recently, no method had been available for assessing the condition of furnace walls whilst the boiler was on-line; this had required a shutdown and full internal scaffolding of the boiler prior to internal inspection. Rowan Technologies has been developing corrosion probes, and more recently corrosion scanners, over the past 12 years, to enable the condition of these heat exchanger tubes to be assessed on-line.

These corrosion scanners are able to directly monitor fireside corrosion over entire boiler walls and whilst the boiler is operational. This paper describes how the scanner systems can be used to monitor this corrosion and how the corrosion can subsequently be controlled.

## **INTRODUCTION**

Furnace wall corrosion is a problem with a long history and is an issue of on-going concern for many boiler operators. Carbon steel or low-alloy boiler wall tubes can suffer considerable corrosion when exposed to the boiler's harsh internal environment, Figure 1. Under oxidising conditions, corrosion rates can be extremely low ( $<0.1\text{mm/yr}$ ) but under highly reducing conditions, rates may increase to values as high as  $9\text{mm/yr}$  [1].

Areas of high corrosion activity tend to be fairly localised, although these locations can vary due to changes in mill and burner configurations, and also because of turbulence within the boiler. Typically, predictions are made (based on manual wall thickness surveys) of likely tube wall metal loss up to the next major outage. If this loss predicts a remaining wall thickness which is less than an allowed minimum, then tubes may be replaced, or perhaps a protective coating added.

The issue of furnace wall corrosion has had a new lease of life over recent years by the introduction of low NO<sub>x</sub> burners (to reduce greenhouse gas emissions) and also changes to the coal feed, as local UK collieries are being closed down and imported coal is being brought in. These factors may cause additional furnace wall corrosion problems where none had previously existed.

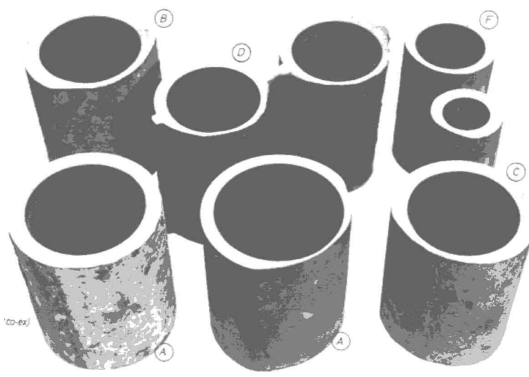
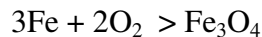


Figure 1: Corroded Furnace Wall Tubes  
(courtesy Lees and Whitehead [1])

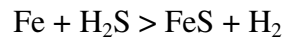
The precise causes of furnace wall corrosion, although now better understood, are still being unravelled and follow many years of research. Most of the work has been carried out in small-scale laboratory or combustion test facilities where the combustion conditions are fairly well controlled. However, it is questionable how well these results relate to large-scale boilers, where combustion conditions can vary enormously with time and location within the boiler.

The basic corrosion mechanisms are described in detail in an EPRI Report, TR-105261 [2]. Under normal oxidising conditions carbon and low-alloy steel are protected from corrosion by the formation of a dense and strongly adherent iron oxide (magnetite) layer:



This magnetite layer grows slowly and the growth rate decreases with time resulting in a negligible rate of corrosion. As the scale is strongly adherent to the tube, it is not easily removed by tube cleaning using compressed air, steam or even high-pressure water washing.

Sulphur contained within the coal forms sulphur dioxide during combustion and this increases the porosity and decreases the adherence of the scale; this alone does not result in high rates of corrosion. However, under reducing conditions with low levels of oxygen and high levels of carbon monoxide, sulphur in the coal may be partially converted to hydrogen sulphide. This preferentially reacts with the carbon or low-alloy steel to produce iron sulphide:



Previously formed magnetite scale may also be converted to iron sulphide. Depending upon the relative amounts of carbon monoxide, sulphur dioxide, hydrogen sulphide and other parameters, the scale may consist of a mixture of magnetite and iron sulphide or sometimes nearly pure iron sulphide. The strength and adherence of the scale decreases with the amount of iron sulphide present and the permeability and growth rate increase significantly. This results in a significantly increased rate of corrosion.

Other factors affecting corrosion include the presence of chlorine in the coal. In the UK, coal chlorine content tends to be high (up to 0.8%) compared with other countries and this was extensively examined by the CEGB [3]. They found that increased chlorine in the coal resulted in increased rates of corrosion but only where reducing conditions were prevalent. Recent work by Powergen/EPRI confirmed these findings and concluded that under reducing conditions, and in the presence of chlorine, metal chlorination came into play and dominated the overall metal loss [4]. Attempts have been made to model some of these corrosion processes using mathematical equations but the practical value of these, when applied to the real world situations, remains questionable. Further factors influencing corrosion are high heat fluxes and the deposition of unburned carbon [5].

Boiler operators in the UK have been addressing the furnace wall corrosion problems in a number of ways: by operating boilers under fairly oxidising conditions (using higher excess air levels), using faceted tubes with thicker fireside walls (typically 9mm) to prolong tube life, applying weld-overlaid corrosion resistant alloys to the tube surfaces, being highly selective on fuel composition and by careful control of burner and mill configurations.

## MANUAL INSPECTION TECHNIQUES

During normal operations, the internal boiler walls are completely inaccessible. Scheduled maintenance, at intervals of typically 3 to 6 years, permits complete access to the inside, once scaffolding is erected. Once the tube surfaces have been cleaned, ultrasonic or EMAT surveys of remaining tube wall thickness are made at levels spaced typically a metre or two apart. Areas of concern are subject to closer inspection. Changes in wall thickness since the previous survey (several years earlier) enable the tube's remaining lifetime to be predicted, assuming corrosion rates remain unchanged.

This lifetime prediction method (used for many years) is based on extrapolation of past corrosion history. It does not, however, predict how the rates will be affected by changes in boiler operation. Rowan Technologies' scanner systems are able to provide this additional information.

## ON-LINE CONDITION MONITORING

Until recently, a reliable method of monitoring furnace wall corrosion, when there is no direct access to the corroding tube walls, remained elusive. Such monitoring is clearly desirable when it is difficult, or impossible, to predict corrosion activity following changes to boiler operations or components.

A range of corrosion probes, and more recently corrosion scanner systems, have been developed and refined by Rowan Technologies over the past decade for monitoring such inaccessible surfaces during normal operations [6,7,8].

### Corrosion Scanner Systems

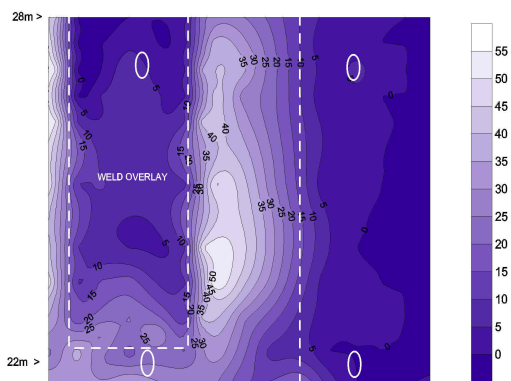


Figure 2: Typical Corrosion Rate Map

The scanner system's measurement technique is based on the well-established electrical resistance principle, where thinning of a metal increases its measured electrical resistance. As this resistance is temperature dependent, metal temperature is also measured and the resistances compensated accordingly. The sensing electrodes used by the scanner systems are directly attached (welded) to the external boiler wall and, during the resistance measurement cycle, current is passed directly through the tube wall. The system electronics detect small increases in resistance (measured in nano-ohms) as the tube wall thins. By installing a matrix of sensor locations, measurements can be made between adjacent sensors to build up complete maps of

corrosion behaviour over large areas of boiler wall, Figure 2. Maps can be presented in a variety of formats: corrosion rate, metal loss, remaining thickness and tube remaining life. Systems are now available in two forms - fixed systems for continuous monitoring, and portable systems for periodic monitoring of corrosion activity at many different locations, for example, in chemical and refinery sites.

Fixed systems have now been installed on two 660MW PF-fired boilers at Drax power station, Figure 3. Drax has six 660 MW boilers: furnace wall tubing generally comprises 6.5 mm thick tubing (with some 9mm replacement tube panelling). These are allowed to corrode to a minimum of 2.5mm, beyond which the tubes may be at risk of tube rupture.

In common with most stations, Drax is continually looking to improve operational efficiency and also has to meet new targets on gaseous emissions. Whilst the boilers undergo modifications to meet these objectives, the station has



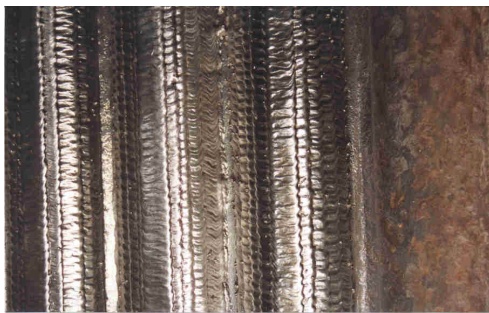
Figure 3: Drax Power Station, UK

sought to monitor and to control corrosion activity with the help of the scanner technology. The scanner systems offer Drax several attractive features:

- Whole areas of furnace tube wall can be monitored directly - a distinct advantage over insert probes which monitor at single locations.
- Despite the hostile and thermally dynamic conditions at the boiler wall, corrosion rates can be quantified, and maps produced, typically within a few weeks from the start of monitoring. Higher rates of corrosion can be quantified more quickly.
- The systems are maintenance free at the boiler wall. Three boilers at Drax have exclusion zones (for safety reasons).
- The systems also provide information about the boiler wall thermal characteristics, for example monitoring slagging/fouling of the boiler walls.

Over the last 4 years, Drax has been gaining valuable information from these systems; their applications at the station are described below.

### Corrosion Evaluation of Weld Overlayed Tubing



*Figure 4: Weld Overlay on Used Tubing*

During the summer of 1999, replacement tube panels were installed in the centre of the Unit 4 boiler sidewalls, where tube wall corrosion was at its most severe. These panels were weld-overlayed, in situ, with up to 3mm of corrosion-resistant Inconel 625 alloy, Figure 4. At the same time a scanner system was installed in the same area of the boiler to monitor the performance of the overlay, Figure 5. The scanner soon confirmed that the overlay was performing well with very low rates of corrosion (less than 0.1 mm/yr) being recorded, in comparison to adjacent non-overlayed tubing, where corrosion rates were much higher (sometimes > 0.8 mm/yr), Figures 6a,b. Note that the scatter on

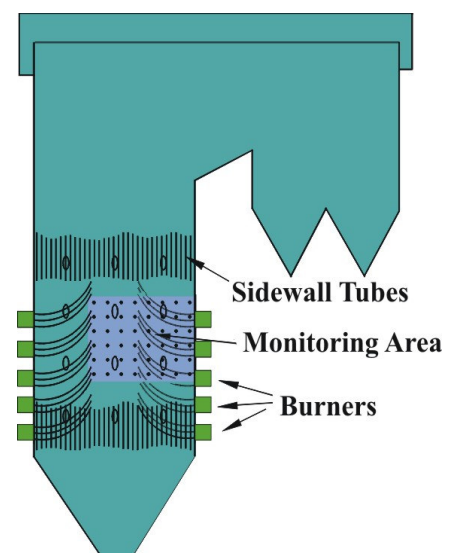
these two (unfiltered) traces is principally due to uncertainties in mean tube temperature caused by the thermally-dynamic boiler environment (i.e. large spatial variations in heat flux caused by slagging of the boiler walls and turbulence of the hot gases). Recent refinements in both hardware and software has led to significantly improved data analysis and presentation.

Analysis of the flue gases, using sampling ports located within the boiler sidewalls, showed that the CO content (an indication of reducing conditions) was highest towards the centre of the sidewall (up to 7000ppm) where corrosion rates were also highest. The CO content towards the corner of the boiler dropped to around 200ppm where corrosion rates were much lower. Thermal information acquired by the scanner showed that the higher corrosion rates were also coincident with higher wall temperatures.

Unit 4 was shut down in the summer of 2002 for scheduled maintenance and EMAT survey data of remaining tube thickness, together with visual observation, were able to verify the scanner's results - with very good overall agreement.

### Corrosion Activity Relating to Fuel and Operations

Data from individual areas showed that corrosion rates varied considerably between summer and winter periods - rates had a tendency to increase over winter and into spring and subside during the summer and autumn periods, Figure 6b. The precise causes of this variation are not known but may be related to seasonal variations in moisture content of coal stockpiles.



*Fig. 5: Unit 4 Scanner Monitoring Location*

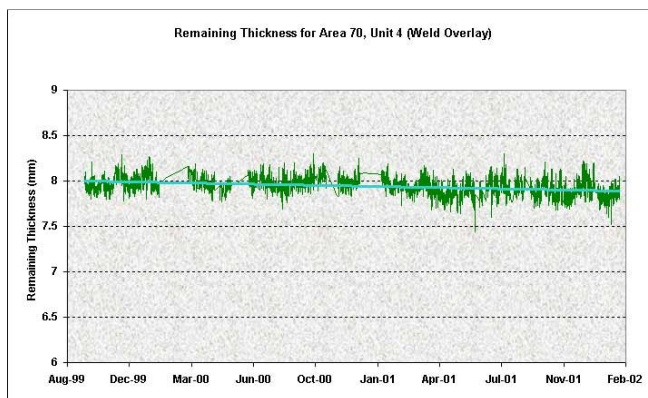


Figure 6a: Thickness Trend—Weld Overlay

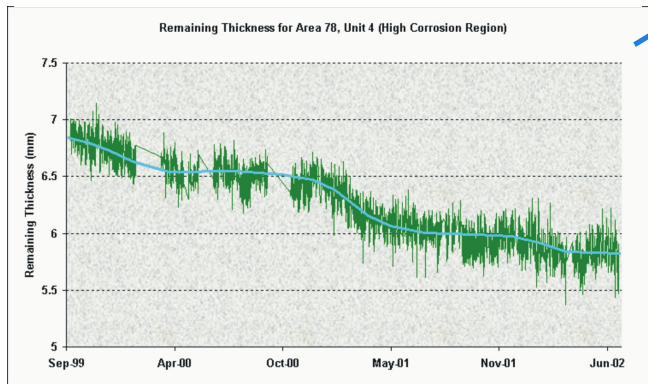


Figure 6b: Thickness Trend—High Corrosion Region

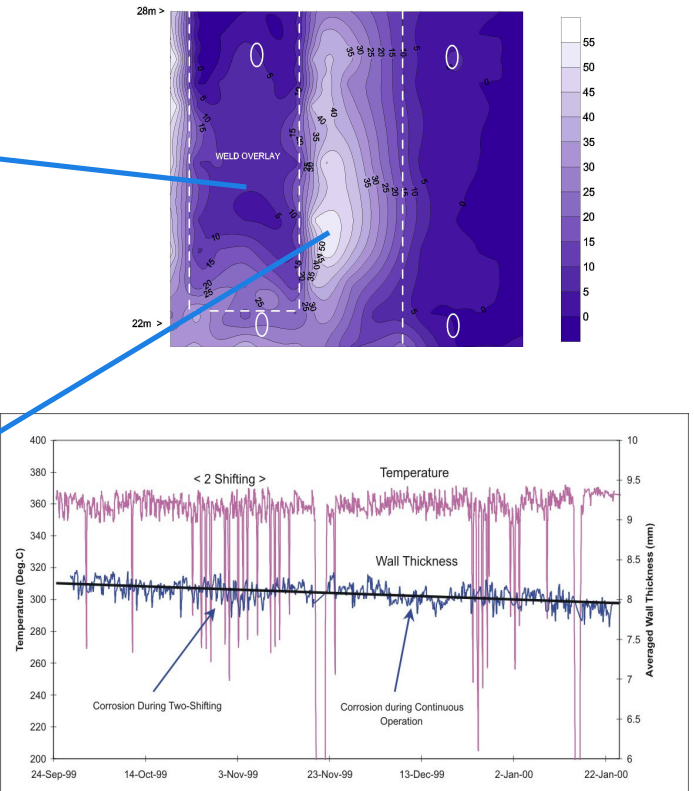


Figure 7: Two-Shifting and Corrosion trends

Depending on market conditions and the demand for electricity, boiler plant may be put on standby during night-time periods. Boilers are taken off load and tube temperatures drop considerably before being brought back on load again the following morning (so called two-shifting). There has been concern at Drax that this thermal cycling may damage the protective tube wall scales and accelerate corrosion. However, data acquired by the scanner suggests this is not the case at Drax, the cycling having little or no influence on the corrosion trends on the sidewalls of this cross-fired boiler, Figure 7.

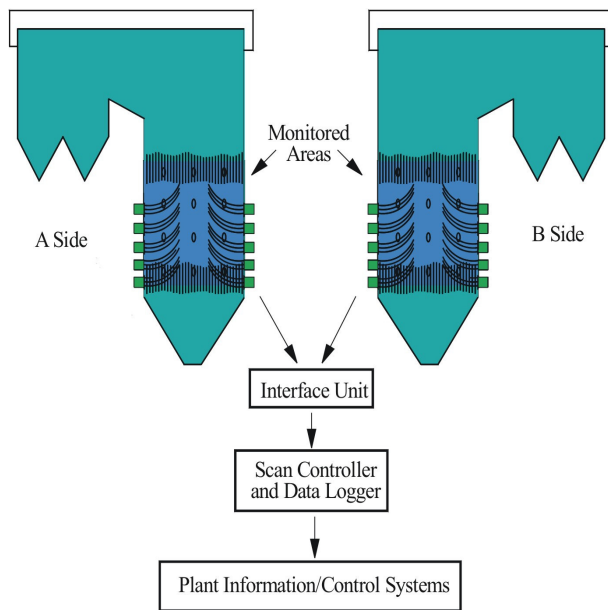
### Corrosion Evaluation following Installation of Low-NO<sub>x</sub> Burners

A second scanner system was installed on Unit 1 in the summer of 2001. This system was considerably larger than the Unit 4 system and covered most of the boiler's two sidewalls, Figure 8. One of the principle roles of this system was to assess the effect of installing a new range of low NO<sub>x</sub> burners on sidewall corrosion:

The Drax boilers are of a high thermal efficiency design - relatively large furnace volumes provide a long residence time for fuel combustion and, combined with turbulent burners and good pulverised fuel fineness, ensured maximum combustion with minimum excess combustion air. However, this high thermal rating is detrimental to NO<sub>x</sub> emissions (not an issue at the time of design). A programme of replacing the existing burners with low NO<sub>x</sub> burners has been undertaken over the past few years. This has produced a corresponding reduction in excess air and an increase in reducing conditions local to the burners. While the reduction in excess air has helped thermal efficiency, the effects on corrosion and boiler slagging have generally increased.

However, to date, the scanner has shown that sidewall corrosion on Unit 1 has generally been low to moderate (typically less than 0.2 mm/yr) since the burners were installed, allaying concerns that corrosion rates might be excessive (and which may have resulted in an early shutdown and internal inspection).





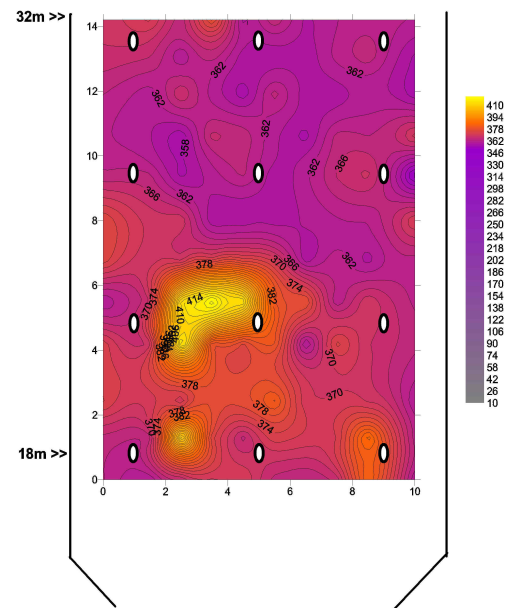
*Figure 8: Unit 1 System Arrangement showing the Interface and Distribution Units*

## Corrosion Assessment of Feedstock Variation

The nearby Selby coalfield, that has supplied Drax with fuel for many years, is due to close in the Spring of 2004 and the boilers will then be fired on coal from other sources. Selby coal typically contains 1.2% sulphur and 0.4% chlorine, but coal from elsewhere may contain significantly higher concentrations of these components. There are also proposals to fire petcoke (a high calorific value fuel) blended with the coal. This is a product from the oil refining process and one that is likely to be more corrosive to fireside surfaces due to its higher sulphur content. It is proposed to install further scanner systems to monitor the effects of burning alternative fuels in combination with coal.

## Boiler Wall Thermal Characteristics

Temperature data acquired by the scanners can itself be valuable to the boiler operators. The temperature sensors can be used to build up maps (in real time) of the boiler wall's thermal characteristics i.e. water/steam, membrane, fireside temperatures and heat flux. These maps are able to show the effectiveness of tube cleaning procedures - a process where compressed air jets are used to remove slag from the tube surfaces during normal boiler operations. The maps also highlight areas with abnormal wall temperatures: a map showing excessive fireside wall temperatures ( $> 480^{\circ}\text{C}$ ) is shown in Figure 9. These excessive temperatures are most probably due to flame impingement from one of the wing-burners. To date this has not led to any seriously increased corrosion at this location although carbon steels should not be exposed to temperatures above  $450^{\circ}\text{C}$  in boilers for extended periods.



*Fig 9 : Typical Thermal Map—Unit 1*

## **DISCUSSION**

Information on corrosion activity and remaining thickness, which the scanner systems provide, helps to remove uncertainty about the effects of changes in boiler components or operations - the outcome of these changes is now known within a matter of weeks rather than years. This helps to provide an early framework for planning future boiler maintenance. If the scanner indicates low rates of corrosion, then this increases confidence in current boiler operations and could allow an extension of the interval between boiler shutdowns and maintenance. If the system warns of an excessive corrosion rate, then boiler operations could be modified to reduce the rates to an acceptable level to achieve the required service life.

Managing furnace wall corrosion with the minimum of cost is clearly a key goal for future power generation. Although the application of weld overlay might technically be the best solution both for new and existing tubing, it is an expensive process - costing some £3000 per square metre. Drax has so far limited the application of weld overlay to small, highly vulnerable areas of tube wall on two of its six boilers. When boiler operations change, areas of previously low corrosion activity can assume higher rates and conversely, areas with previously high activity can become low. Consequently, it can be difficult deciding where overlay would be the best option.

Where furnace wall tube panels are replaced at Drax, original 6.5mm wall tubing may be replaced with 9mm faceted tubing, which generally has an increased lifetime. The installed cost of a single panel (roughly 15m high and 15 tubes wide) is around £38K. Applying weld overlay to a single panel costs around £50K, i.e £88K for a replacement weld overlaid panel. These costs do not take into account the loss in generating income while the boiler is shutdown. The cost of corrosion scanners typically range between £20 - £40K depending upon the area to be monitored. If the need for shutdown, inspection, tube replacement or the application of weld overlay can be reduced to a minimum then clearly the cost savings are substantial. The scanner systems are proving to play a key role at Drax power station in achieving this aim.

As the local Selby coalfield nears closure, coal from other sources will be supplied to Drax, and this is likely to vary in chlorine and sulphur content from existing supplies. The scanner systems will allow Drax to assess corrosion activity within a matter of weeks when these replacement coals are burned. This will allow combustion parameters to be modified to optimise boiler operation and to control corrosion. Optimising boiler operation will become increasingly important from January 2005 when the EU carbon emissions trading scheme is introduced to minimise the production of greenhouse gas emissions from power generating plant.

## **CONCLUSIONS**

1. The scanner systems have shown their ability to provide information otherwise unobtainable during normal operations. Corrosion maps provide a good indication of corrosion rates and remaining tube thickness without the need for internal boiler inspection.
2. The scanners assist in targeted replacement of furnace wall tubing. The amount of furnace scaffolding can be reduced, thus minimising outage duration and costs.
3. The scanners allow boiler parameters to be optimised in terms of efficiency whilst maintaining corrosion activity at acceptable levels.
4. Increased confidence in levels of corrosion activity can allow for extended periods of boiler operation prior to shutdown and maintenance.
5. The scanner's thermal data can also be used to provide real time maps of wall temperatures, heat flux and fouling, thus assisting the boiler operators to schedule tube cleaning procedures.

6. Systems are available in two forms: fixed systems for continuous monitoring, and portable systems to periodically monitor corrosion at many different locations, for example, in chemical and refinery sites.

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