INVESTIGATION INTO REHEATER DRYING DURING BOILER SHUT DOWN

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A research report submitted to the Faculty of Engineering and the Built Environment, University of the Witwatersrand, Johannesburg, in partial fulfilment of the requirements for the degree of Master of Science in Engineering

Johannesburg, May 2015

DECLARATION

I declare that this research report is my own unaided work. It is being submitted for the Degree of Master of Science in Engineering to the University of the Witwatersrand, Johannesburg. It has not been submitted before for any degree or examination to any other university

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12 May 2015

ABSTRACT

Boiler tube failures (BTF) are the leading cause of plant downtime and can cost utilities tens of millions of dollars. One of the mechanisms of BTF is pitting corrosion in the steam side of tubes of reheater and superheater tubes. Pitting corrosion in these tubes is a result of poor shut down and layup practices of the boiler leaving stagnant oxygen rich water in the tubes during the outage period.

Three methods of drying reheater tubes during the shutdown process exist within the South African environment. These are forced drying, vacuum drying and boil drying. This research looked at determining which of the three methods is the most effective, by analysing the moisture content of the fluid inside the reheater tubes at the end of the drying procedure. This was achieved by measuring the relative humidity and dew point of the air/water mixture within the reheater tubes at seven power stations.

It was found that forced drying is the most effective method as it produced a fluid within the reheaters dryer than ambient air. The fluid remaining in the reheater at Power Station A had a relative humidity of 13.7% at 31.5°C and a dew point of 0.9°C as compared to the ambient air of 47% relative humidity at 25.8°C with a dew point of 17.3°C. Forced drying allows a large volume flow of air through the reheaters effectively replacing the steam with dry air. Vacuum and boil drying leaves a fluid with 100% humidity within the reheater, which will cool and condense and will result in pitting corrosion. Vacuum and boil drying do not effectively replace the steam with dry air. The power stations making use of vacuum as well as the one making use of boil drying had a fluid in the reheaters with a relative humidity of 100%.

This research has shown that forced drying while the boiler is hot is an effective method of drying. Further, offline corrosion can be prevented by keeping the boiler in low humidity conditions. This is achieved by circulating dehumidified air through the boiler tubes.

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LIST OF ABBREVIATIONS

BTF	Boiler tube failure
EPRI	Electric Power Research Institute
ESV	Emergency stop valve
FD	Forced draught
GV	Governor valve
HP	High pressure
ID	Induced draught
IP	Intermediary pressure
LP	Low pressure
PA	Primary air
RH	Relative humidity
SA	Secondary air
SCR	Selective catalytic reduction
UCLF	Unplanned capability loss factor

LIST OF SYMBOLS

a_{Yi}	Instrument uncertainty with respect to parameter Yi
Cl^-	Chloride anion
D	Diameter of pipe
Ɛ	Relative roughness of pipe
e^-	Electron
f	Fanning friction factor
f_e	Frictional losses for sudden enlargement
Fe_3O_4	Iron (II,III) oxide
H^+	Hydrogen ion
H_{vap}	Enthalpy of vaporisation
K	Frictional losses through valve
L	Length of pipe
M^+	Metal cation
Na^+	Sodium cation
Na_2SO_4	Sodium sulphate
NO_x	Oxides of Nitrogen
O_2	Oxygen gas
OH^-	Hydroxide ion
ΔP	Pressure drop
Re	Reynolds number
RH	Relative humidity
R_{air}	Gas constant for dry air
R_w	Gas constant for water vapour

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CHAPTER 1: GENERAL INTRODUCTION

1.1 Introduction

South Africa's demand for electricity has increased in recent years, putting a strain on the electricity supply system [1]. Any unplanned outages on the electricity generation side can lead to load shedding, as the demand is greater than the supply. It is of utmost importance to reduce the amount of any unplanned outages.

Africa's major power producer, Eskom, reported that the Unplanned Capability Loss Factor (UCLF) was 12.12% for the period ending 2013 [2,3]. According to Eskom's financial report [2], "UCLF is a measure of the lost energy due to unplanned production interruptions resulting from equipment failures and other plant conditions". The turbine failure at Duvha Power Station contributed to 1.17% of the UCLF. However, 3.4% of the total UCLF was due to emission control and short term outages amongst other boiler tube failures (BTF) [3], leaving 7.55% due to energy losses from operations [2,3]. The total UCLF during 2013 is greater than 7.97% and 6.14% for the periods ending March 2012 and March 2011, respectively [2,3]. The North American annual average UCLF for fossil-fuelled power plants between 2005 and 2009 was 7.93% [4]. BTF's are the most significant contributors to UCLF in Eskom power stations [5].

In the USA, more than 50% of forced outages in the power generation industry are related to corrosion problems [6,7]. Financially this accounted for over $3 billion in additional operating and maintenance costs [6] with $669.14 million in coal-fired power plants in the USA [7] and can add up to almost 10% of the cost of electricity [6]. Reducing the amount of forced outages and prevention of corrosion related problems in the power generation industry can reduce the cost of electricity as well as, enable plant availability for longer periods.

One of the causes of unplanned outages at the power stations is boiler tube failures, whereby the steam tubes rupture forcing the unit to shut down. Tubes can fail due to conditions on the outside of the tube such as fly ash erosion or fireside corrosion [8]. Other failures include those on the inside of the tube. One of the mechanisms by which tubes fail is due to 'steam side pitting corrosion' within the reheater tubes especially during offline conditions. Pitting corrosion is the result of insufficient drying during the shutdown of the boiler. Figure 1-1 depicts the internal of a steam side of a tube (steam-touched) subjected to pitting corrosion.

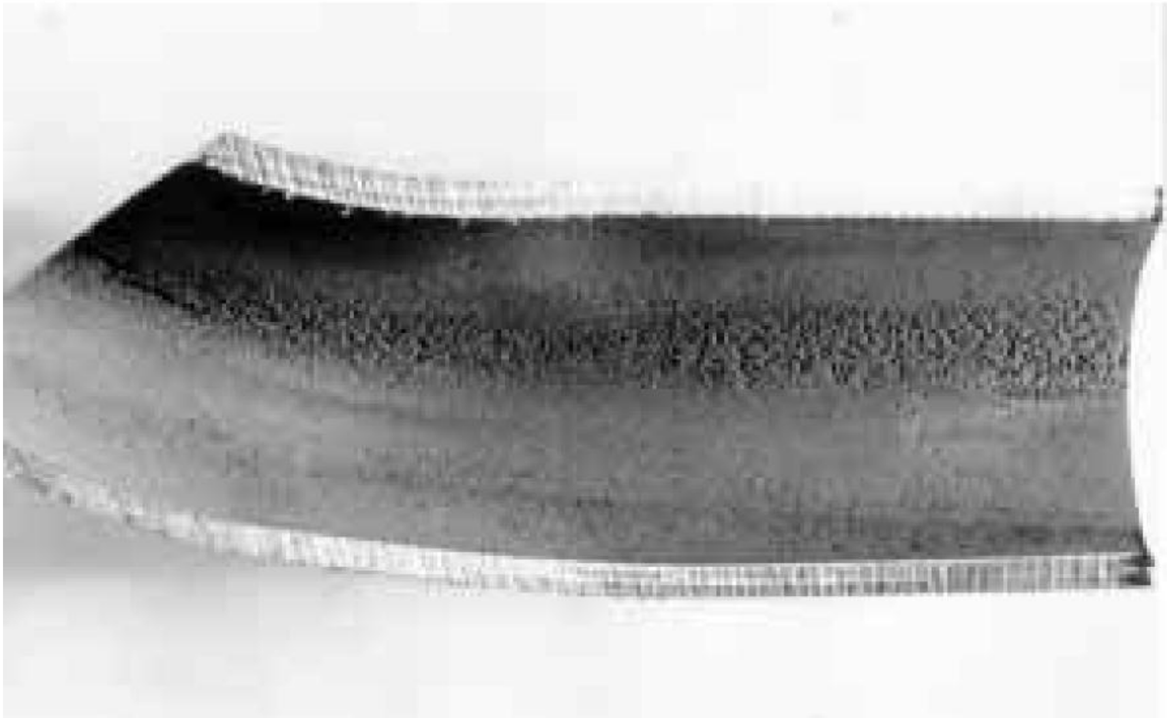

Figure 1-1: Internal of superheater tube subjected to pitting corrosion [9]

Pitting corrosion related problems in reheater tubes are the basis of this research project.

1.2 Research Problem

One of the mechanisms, which cause boiler tube failure in conventional boilers, is pitting corrosion [9,10].

There are three main causes of pitting in steam-touched tubes [9]:

1. Oxygen-saturated stagnant water formed as a result of poor shut down practices;
2. Mechanical carryover of Na_2SO_4 in steam during operation which then combines with condensate formed during shut down; and
3. Chemical cleaning damage.

The first cause of corrosion mentioned above is due to poor shut down practices causing stagnant water to form in the low-lying areas of the steam tubes. These can be either superheater or reheater tubes in the bottom of pendant loops or the low points of staging horizontal tubes [9] as illustrated in Figure 1-2 and Figure 1-3 by A and B respectively.

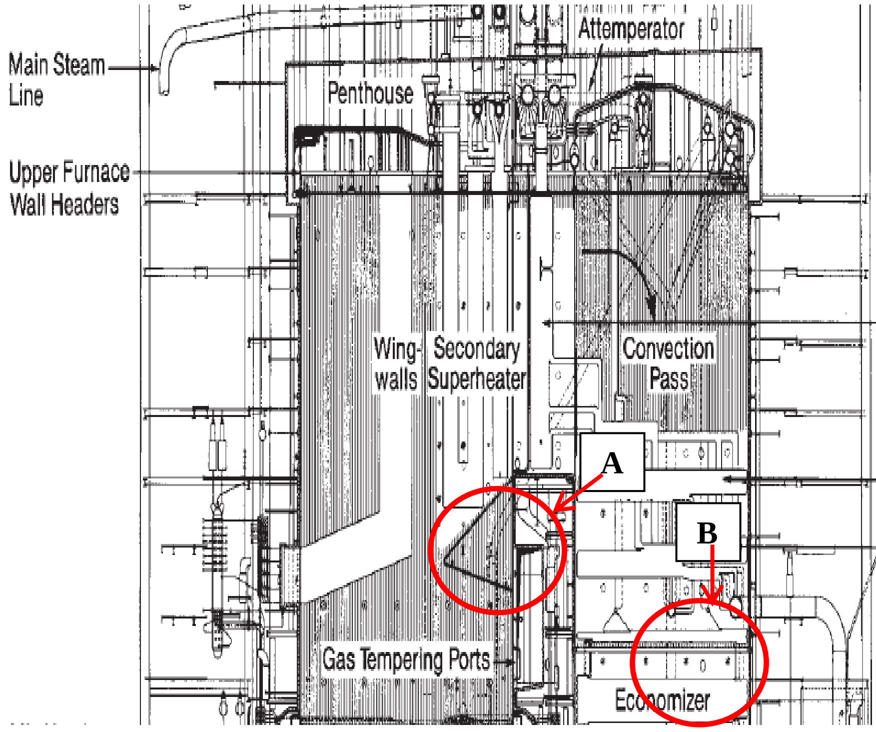

Figure 1-2: Drawing of typical boiler [11]

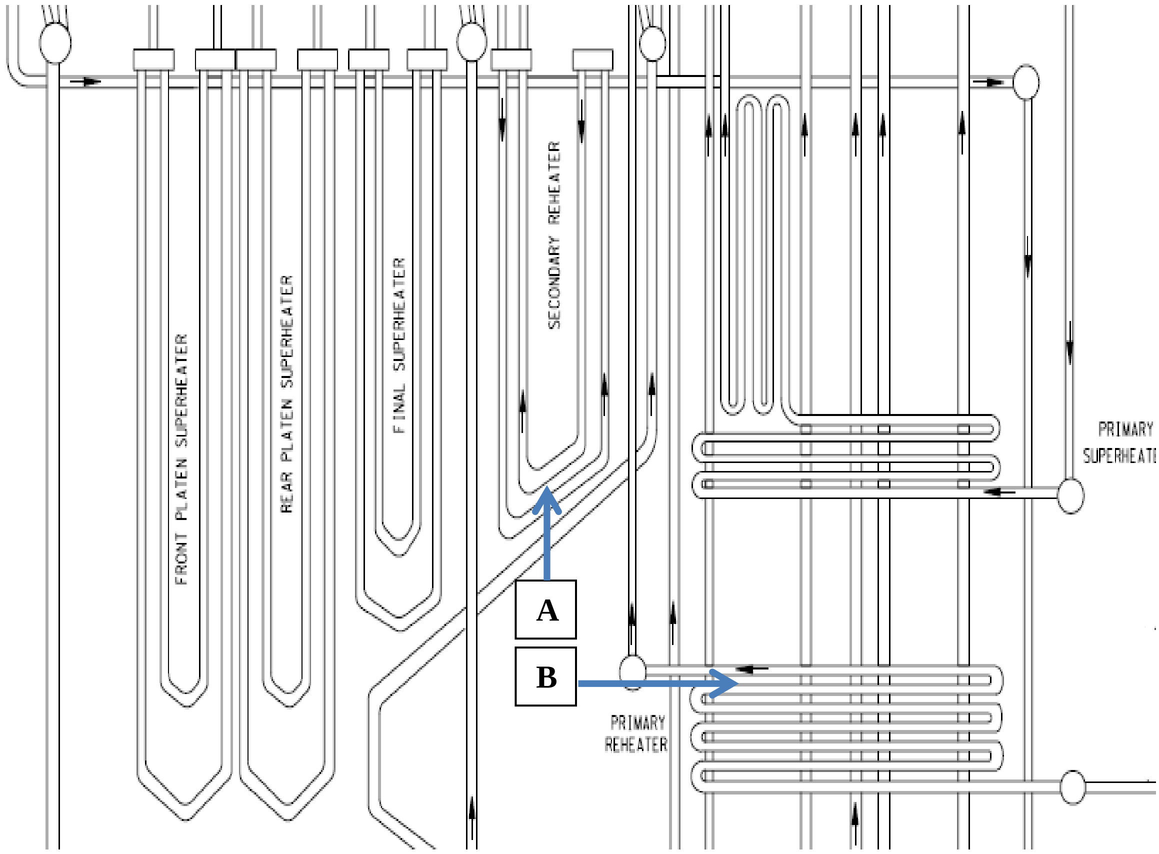

Figure 1-3: Drawing of boiler convective pass [12]

During boiler shut down, there are procedures that are put in place for drying of the reheaters to avoid pitting corrosion, however, pitting is still a problem.

1.3 Aims of the Study

This research aims to investigate which of the three reheater drying procedures used in the South African environment is the most effective. Three methods of drying currently used for reheater drying, these are forced, vacuum and boil drying. Other preventative methods include procedures to store (lay-up) the boiler after drying which include wet and dry storage of the boiler to prevent pitting corrosion during the non-operating period. The three methods of drying are:

- Forced drying which makes use of a fan/compressor to force air into the reheater circuit and evacuate steam out the blow down vessel or steam vents [13].
- Vacuum drying, which uses the condenser vacuum to draw air from the air inlet valve through the reheaters and evacuate steam out of the condenser [14].
- The boil method, which opens the reheater, vents and drains, while burning fuel oil in the furnace attempting to boil out any moisture inside the reheaters [15].

This study thus determines which of the three methods is the most effective.

The structure of this research report is as follows:

Chapter 2 provides a literature review beginning with the basic principles, operations and equipment used in a fossil-fuelled electricity generating plant. BTF's are discussed with a focus on tube failures associated with pitting corrosion. Guidelines for shut down and layup of the plant with the aim of minimising off-line corrosion presented.

Chapter 3 describes the methodology used during the experimental testing of the effectiveness of three shut down procedures used to dry boiler reheater tubes to prevent pitting corrosion. The three shut down procedures and equipment set-up are also described.

Chapter 4 discusses the results obtained from the tests conducted at the three power stations. The results, plus those from another four power station, are analysed to determine which of the three shut down procedures are the most effective in preventing pitting corrosion of the reheater tubes.

Chapter 5 concludes the research report based on the findings in the experimental testing and corroborates the findings with the relevant literature.

CHAPTER 2: LITERATURE REVIEW

2.1 *Operations of a Coal Fired Power Plant*

Modern power stations make use of steam generators or boilers where a fuel is burnt and the energy transferred as heat to water to produce steam [16-19]. The steam is used to drive a turbo-generator to generate electricity. Figure 2-1 [16] depicts the schematic of a modern coal fired power station.

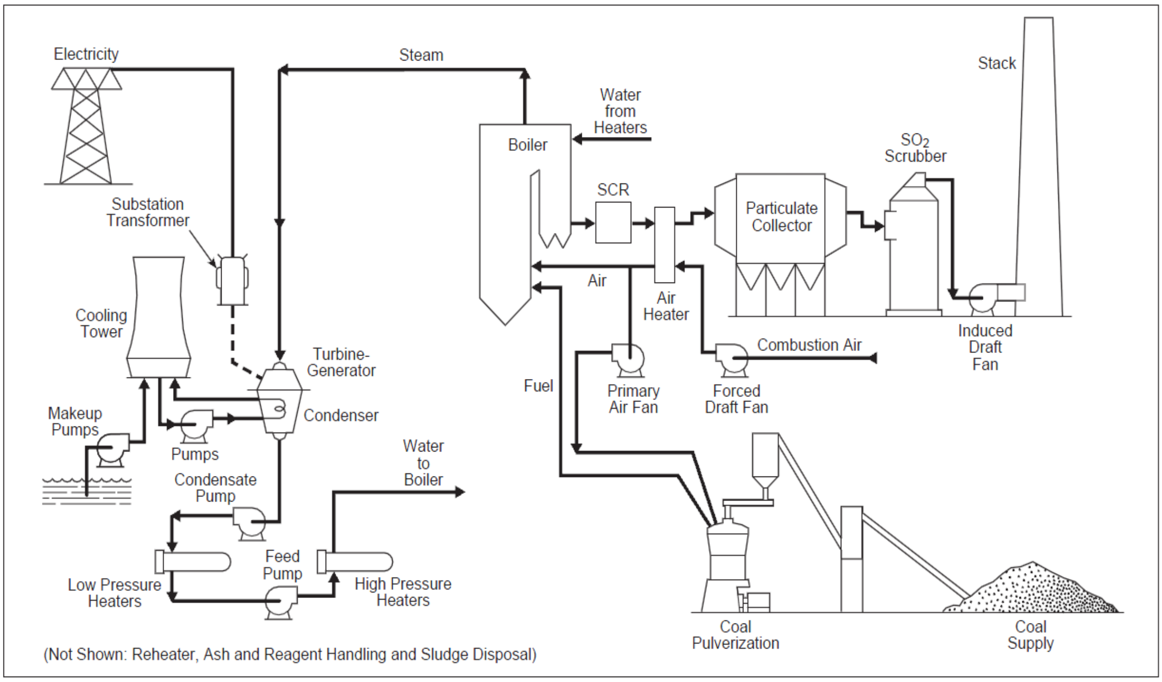

Figure 2-1: Schematic of a typical coal fired power plant [16]

There are three main flows within a power station, these are coal/ash flow, water/steam flow and air/gas flow. Coal from the stockpiles is conveyed to the boiler house where, via a mill feeder, it is fed to the mills for grinding. Secondary air (SA) also known as combustion air is supplied to the boiler with a forced draught (FD) fan. Primary air (PA) which is used to dry the coal as well as transport the coal to the boiler is supplied by a primary air fan. Both the SA and PA are heated in a regenerative air heater using flue gas as the heat source[16-20]. The pulverised coal is pneumatically transported using primary air into the boiler through the burner. Secondary air enters the burner and provides the oxygen required for combustion. Coarse ash falls to the ash hopper at the bottom of the boiler where it is disposed of in the ash dams. The remaining products of combustion together with fly ash pass through the boiler where heat energy in the hot flue gas is transferred to the water/steam via a network of heat exchange tubes within the boiler. The remaining heat energy in the flue gas is used to heat up the primary and secondary air in the air heater needed for conveying the pulverised coal to the boiler (primary air) and air required for combustion (secondary air). The flue gas is then cleaned using the SCR (selective catalytic reduction) for NOx reduction, the particulate collector for fly ash and the SO_2 scrubber before being discharged into the atmosphere through the stack (chimney) by the induced draught (ID) fan [16-20]. South Africa's power utility Eskom currently does not make use of the SCR or the SO_2 scrubber, however, there are plans to include the SO_2 scrubber in their new station currently under construction [21].

Demineralised water from the water treatment plant enters the boiler after a series of preheating steps. The water is pumped into the boiler network of heat exchangers where it evaporates and it ultimately forms superheated steam. The steam leaves the boiler and enters the turbo-generator sets, which generate electricity. The steam leaves the turbines and is condensed in the condenser where it is then recycled to the boiler [16,17,20].

Figure 2-2 depicts a typical utility boiler (drum type) identifying the major components and heat exchangers in the boiler. Water from the feed heaters enters the economiser via the feedwater pump at the back end of the boiler. Here heat energy in the cooler flue gas is transferred to the water, which in a typical sub-critical utility boiler can be at pressures of approximately 18MPa [16]. In a drum boiler as depicted in Figure 2-2, the water from the economiser goes to the drum. From the drum, the water goes via the downcomers to the bottom headers of the boiler.

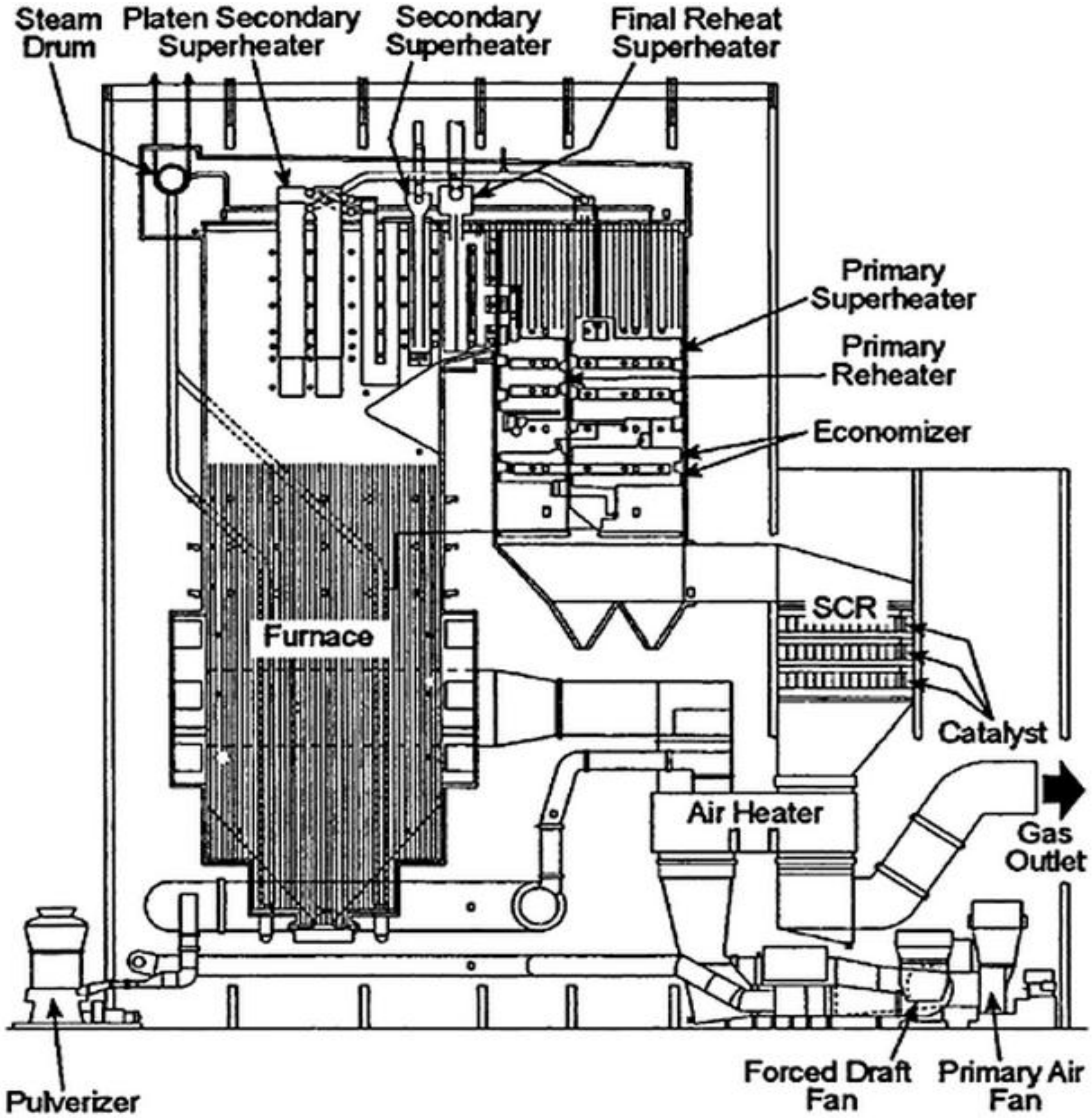

Figure 2-2: Typical coal fired utility boiler [22]

The water then enters the furnace region of the boiler in the waterwalls of the boiler. The boiler walls are made of carbon steel tubes welded together to allow the flow of water from the bottom header through the walls of the boiler back to the drum. This section is also known as the evaporator. Natural circulation in a drum boiler exists due to the temperature/density difference between water in the downcomers and the waterwalls. The waterwall is where phase change of water takes place forming a mixture of saturated vapour and liquid. This mixture enters the drum where steam is separated from liquid water. The water is recycled back to the waterwall while saturated steam leaves the drum at the top.

The saturated steam then goes into the convective section of the boiler entering the primary superheater where it gains additional heat energy to become superheated steam. The steam then enters the secondary superheater section where the design temperature is attained. This superheated steam (known as main steam) then leaves the boiler and goes to the high-pressure (HP) turbine via the emergency stop valve (ESV) and governor valve (GV). The GV is used to control the steam flow. The steam leaves the HP turbine at a lower temperature and pressure (approximately 4MPa [16]) and is known as cold reheat. The cold reheat steam is still superheated steam but at lower pressure and temperature. The cold reheat enters the primary and secondary reheaters within the boiler gaining additional heat energy from the flue gas to increase the temperature. The steam then leaves the reheaters as hot reheat and passes through the intermediate pressure (IP) turbine. Losing additional pressure and temperature, the steam leaves the IP turbine and enters two low-pressure (LP) turbines. The steam is then condensed in the condenser and is recycled to the boiler via the feedwater heaters. Figure 2-3 below depicts the entire steam/water circuit with typical mass and energy values for a 360MW boiler [23]. Vessels 1 and 2 are the high-pressure (HP) heaters while 3-6 are the low-pressure (LP) heaters. Steam is tapped off from the turbines as indicated by A-G as the heating medium in the HP and LP heaters.

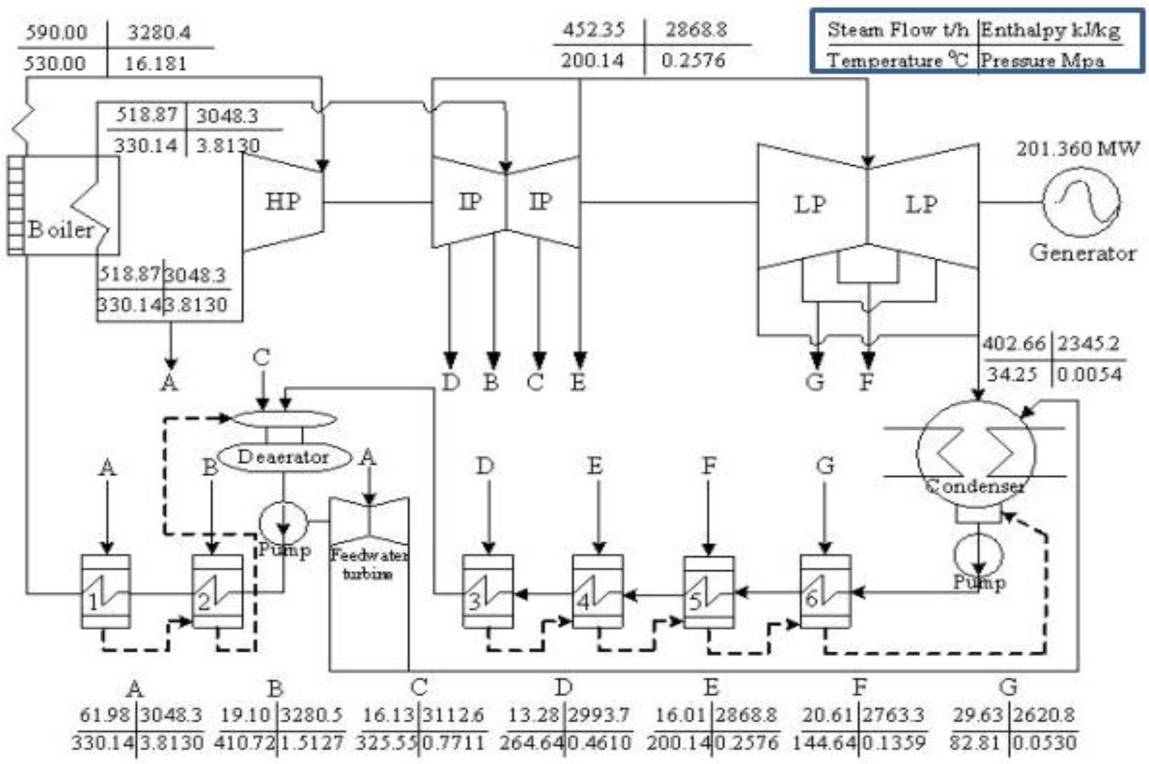

Figure 2-3: Steam flow diagram [23]

In a once through boiler as depicted in Figure 2-4, water is continually pumped through the evaporator and superheater section of the boiler. A steam separator separates phases and if needed circulation pumps are used to maintain pressure and flow [16].

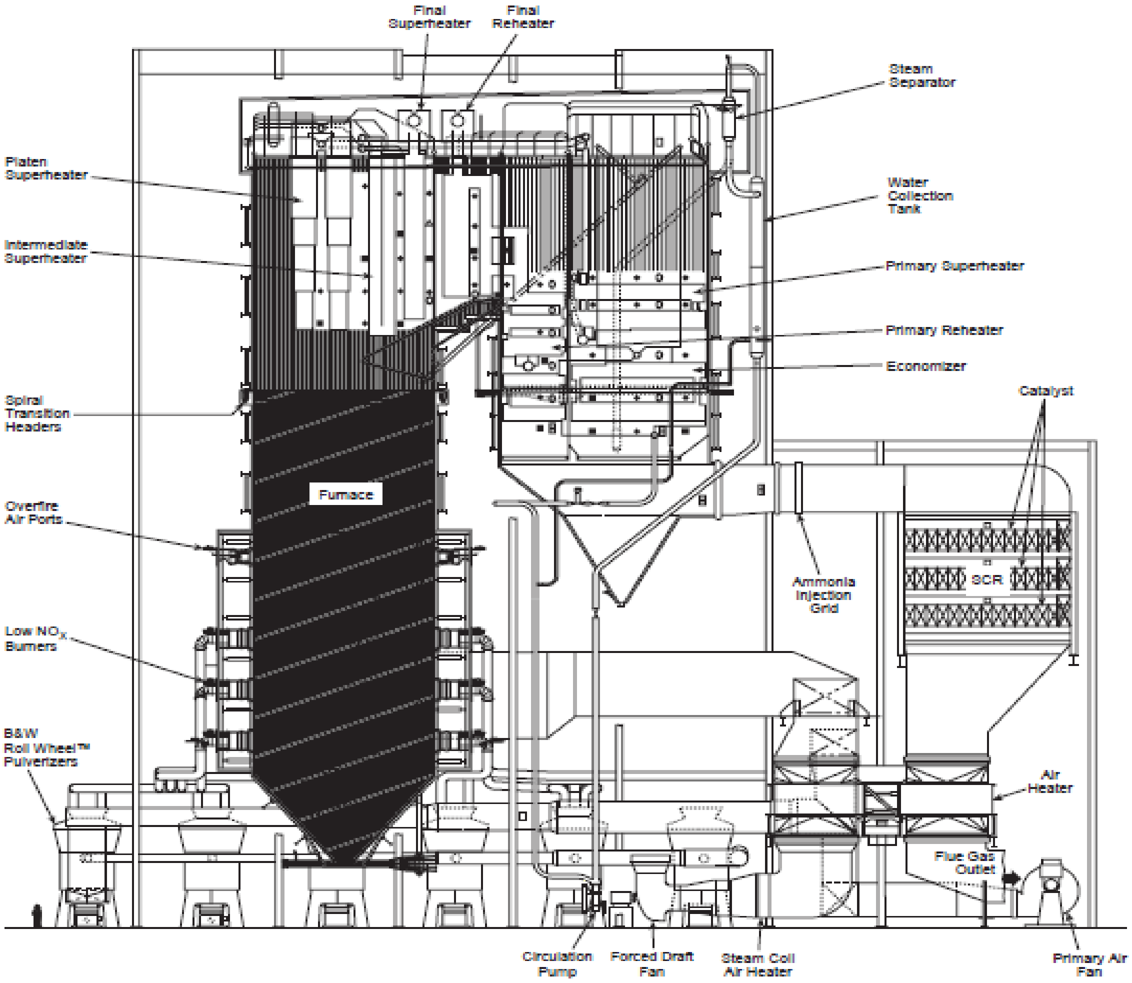

Figure 2-4: Once through 2-pass boiler [16]

The remaining steam flow through the turbine sets and reheaters is the same as the drum type boiler.

The boilers can be configured in either a 2-pass boiler as depicted above in Figure 2-4 with both pendant loop reheater banks as well as horizontal reheater banks while the tower type boiler in Figure 2-5 only has horizontal reheater banks.

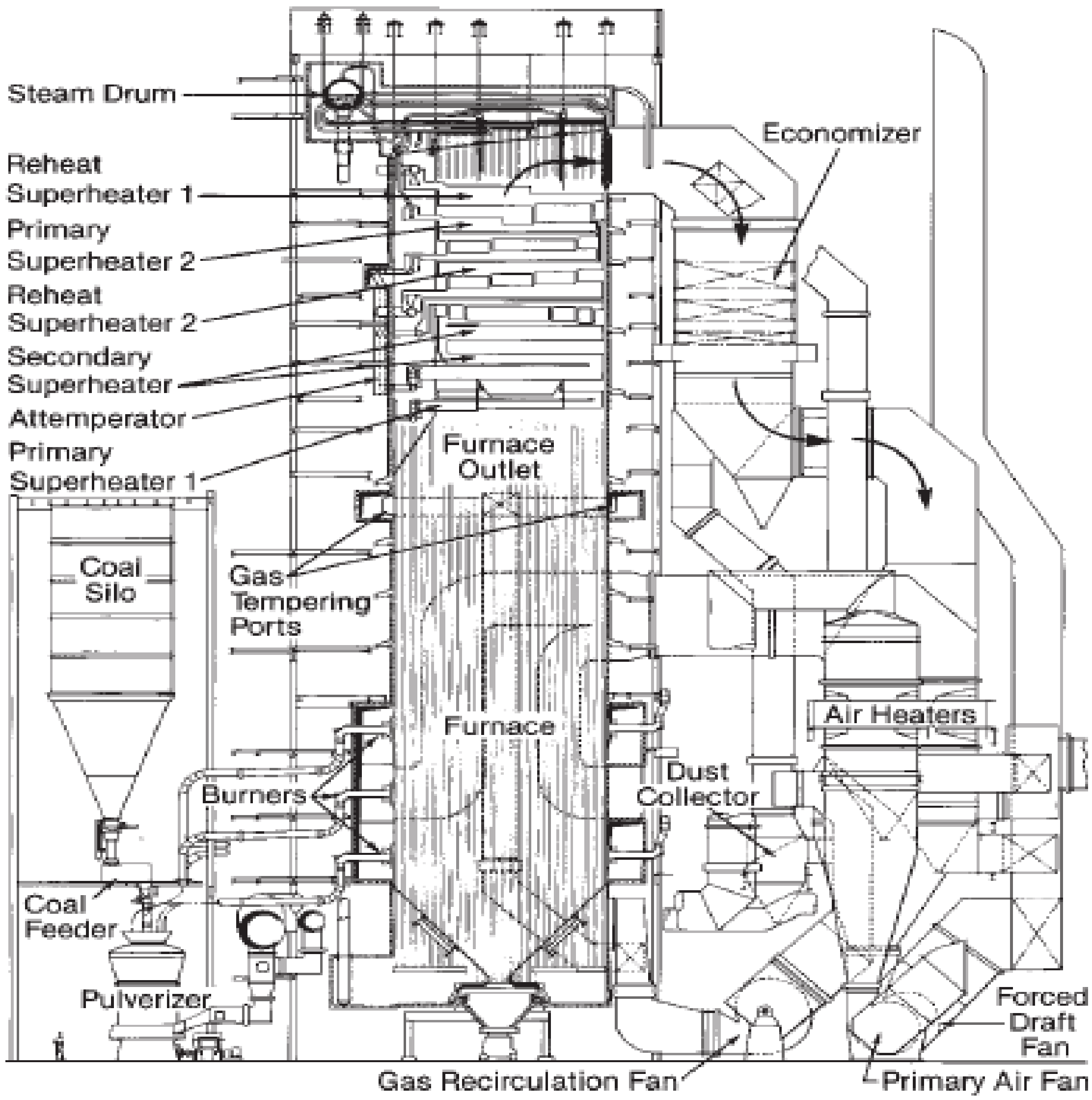

Figure 2-5: Drum type tower boiler [16]

2.2 Boiler Tube Failures

In the power industry, boiler tube failures (BTF) account for 2-3% of the total lost availability in the US [9]. Financially, these plant-generating outages account for in excess of $1 billion as reported by EPRI [9]. From 88 utilities, 43% reported the BTF-related outages to be in excess of $5 million/year while 17% reported the BTF caused outages to be in excess of $20 million/year [24]. All areas in the boiler have BTF with more than 80% of failures leading to plant shut down [9,25]. Eskom reported that boiler tube failures are the leading contributor to its UCLF (Unplanned Capability Loss Factor) [2,3,5].

The following are some of the mechanisms, which cause BTF [8-10,24,25]:

- Corrosion fatigue in conventional boilers
- Fly ash erosion
- Acid phosphate corrosion
- Caustic gouging
- Waterwall fireside corrosion
- Thermal fatigue in waterwalls
- Thermal fatigue in economizer inlet headers
- Thermal-mechanical fatigue and vibration-induced fatigue in water touched tubes
- Water blower thermal fatigue
- Flow-accelerated corrosion in economizer inlet headers of conventional boilers
- Sootblower erosion (water-touched tubes)
- Short-term overheating in waterwall tubing
- Low temperature creep cracking
- Chemical cleaning damage
- Hydrogen damage
- Weld failures
- Pitting
- Falling slag damage
- Acid dew point corrosion

Mechanical failures account for 81% of failures whereas corrosion related incidents account for the remaining 19% [26].

Table 2-1 provides a breakdown of the corrosion related failures and shows that oxygen pitting accounts for 10.8% of the total corrosion related problems [26].

Table 2-1: Breakdown of corrosion failures[1] [26]

Corrosion Mechanism	Percentage
Boiler feedwater	37.2%
Hydrogen damage	20.0%
Ash	19.2%
Oxygen pitting	10.8%
Stress corrosion cracking	8.1%
Caustic attack	4.5%
Others	4.0%

Figure 2-6 depicts the number of boiler tube failures between 1987 and 2003 in NSW (New South Wales) Australia [27]. Pitting corrosion in steam touched tubes falls under the off load corrosion mechanisms when the steam has condensed [9].

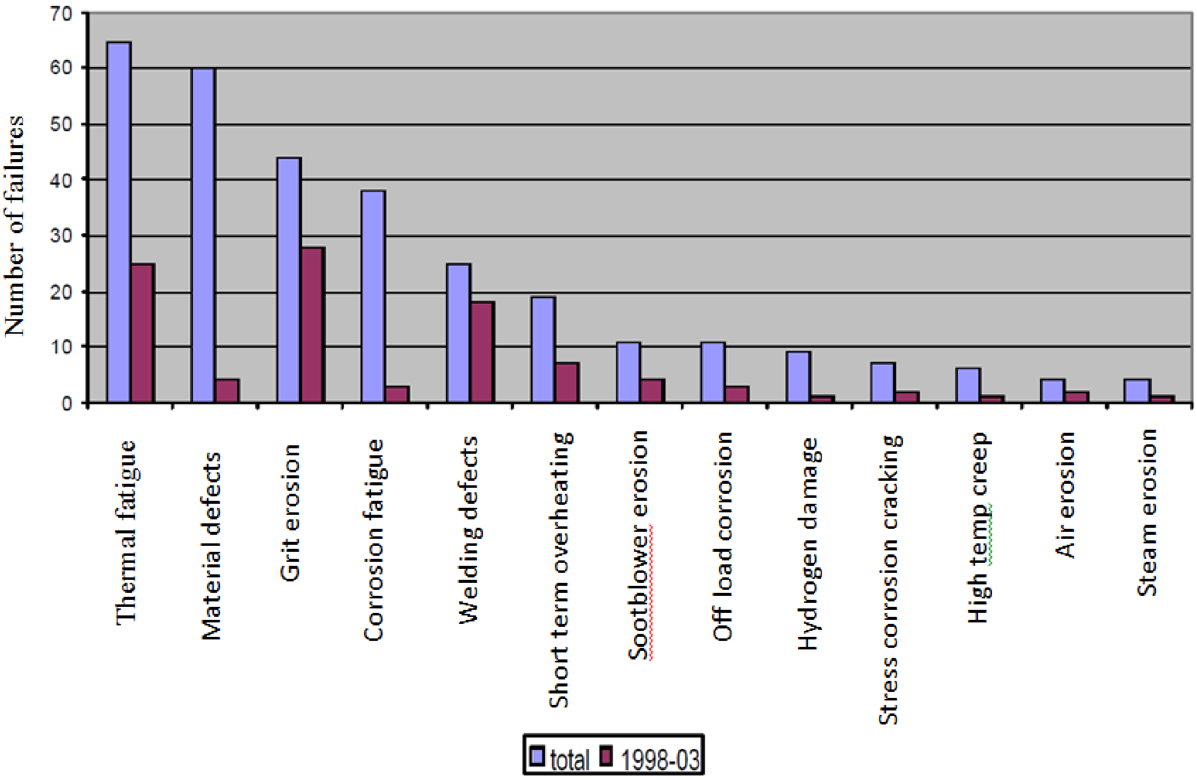

Figure 2-6: Tube failure types in New South Wales, Australia 1987-2003 [27]

[1] Information gathered over 20 years from failure analysis reports on samples sent by customers to the Riley Stoker Corporation. Based in the USA with clients all over the world.

Figure 2-7 depicts the number of failures, which occurred at one power station at Eskom over a 35-year period. The reduction in the tube leaks is due to the implementation of a tube failure reduction programme. The increase in tube failures towards the end of the 35 years is due to tubes coming to the end of their design life and failing [28].

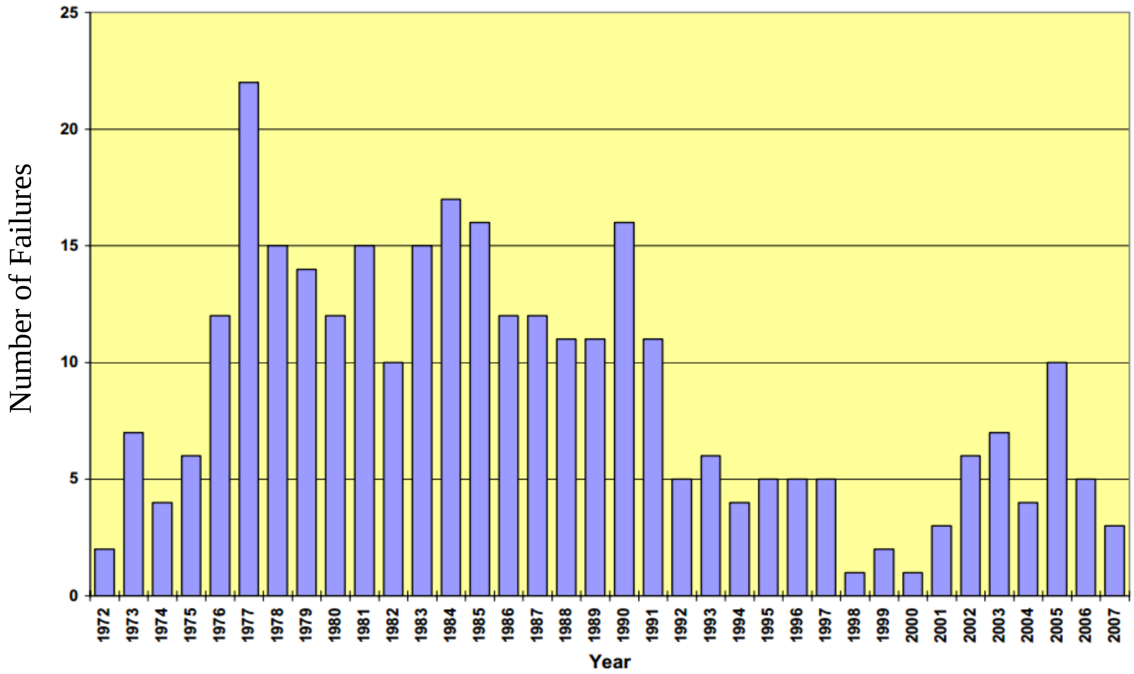

Figure 2-7: Total number of boiler tube failures at Arnot Power Station [28]

As reported by Tarr [28] in the years 2007 - 2011 one of the emerging mechanisms of failures is reheater pitting. The emergence of pitting in the latter stages of the plant life could be because of the pit formation during the many outages, which is now leading to failures. The time in which pits can initiate may be in order of days or years depending on the metal and aggressiveness of the environment [22].

2.3 Pitting Corrosion

In the USA, more than 50% of forced outages in the power generation industry are related to corrosion problems [6]. Corrosion related issues accounted for over $3 billion in additional operating and maintenance costs [6].

Pitting corrosion is a localised corrosion mechanism forming pits or holes in the metal. The damage is usually deep with the small area of the pit [9,29-31]. This is depicted in Figure 2-8 to Figure 2-10 [32]. The pit sites can be filled with corrosion product or may be open depending on the conditions when the pit was formed [29]. With just a small weight loss in metal structure pitting can cause failure as the wall become thin and can also lead to through-wall holes [29,30]. Detection of pits can be difficult as pits are generally small and can be covered by a cap of the corrosion product [30].

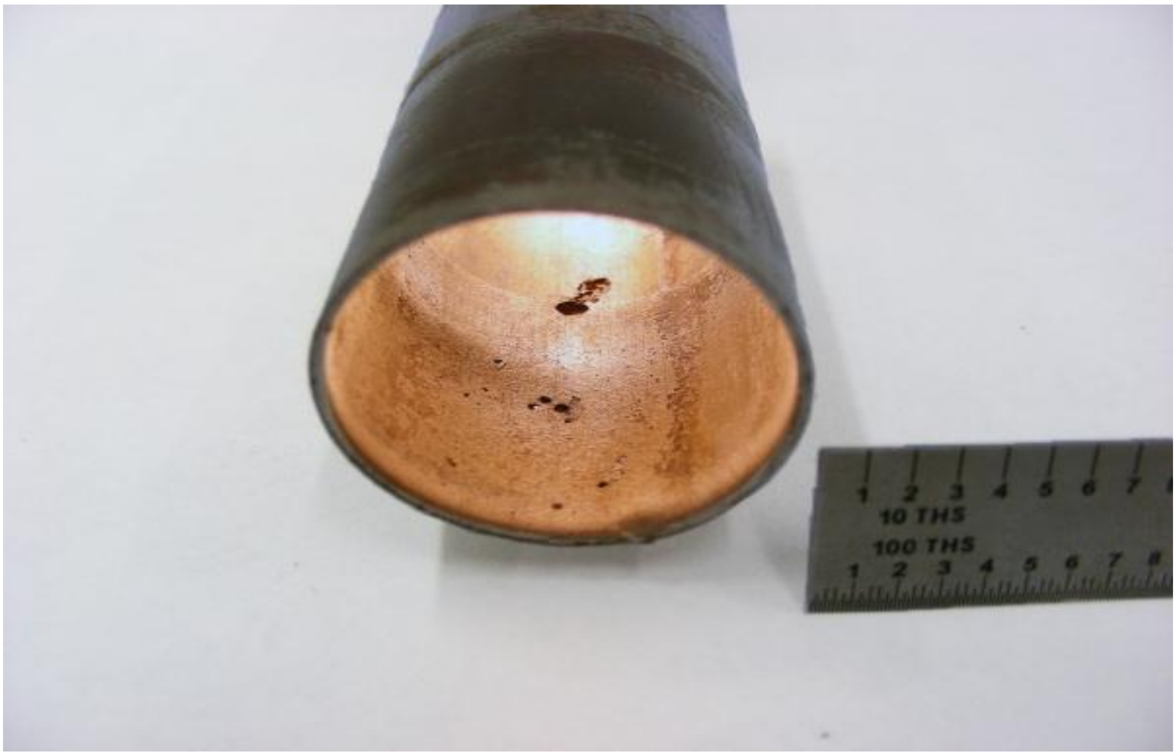

Figure 2-8 : Pitting corrosion in boiler tube A [32]

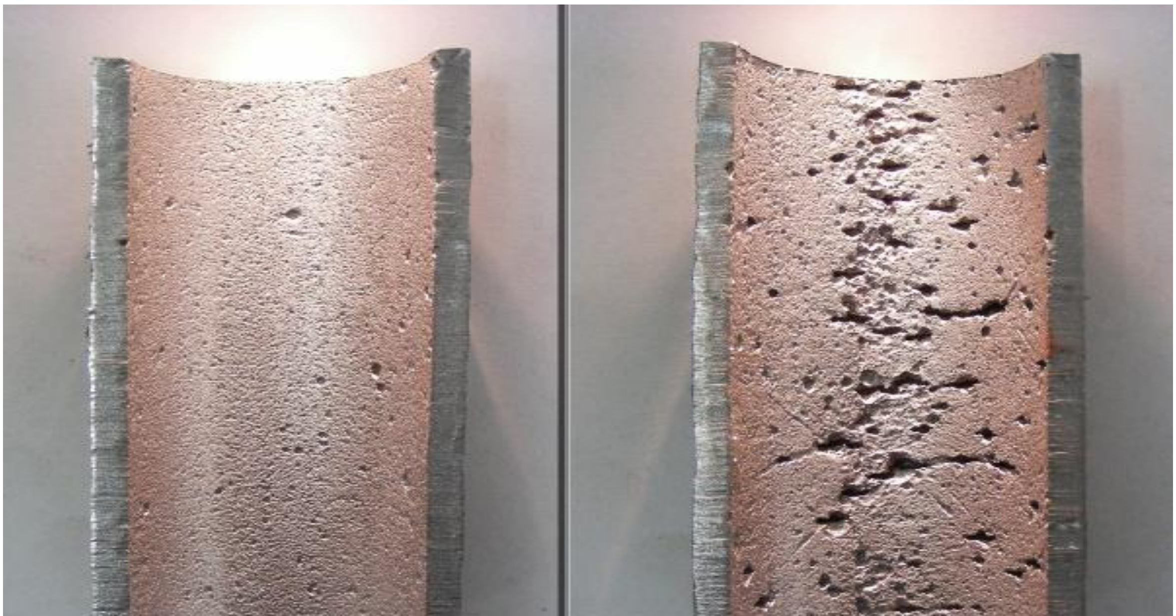

Figure 2-9: Pitting corrosion in boiler tube B [32]

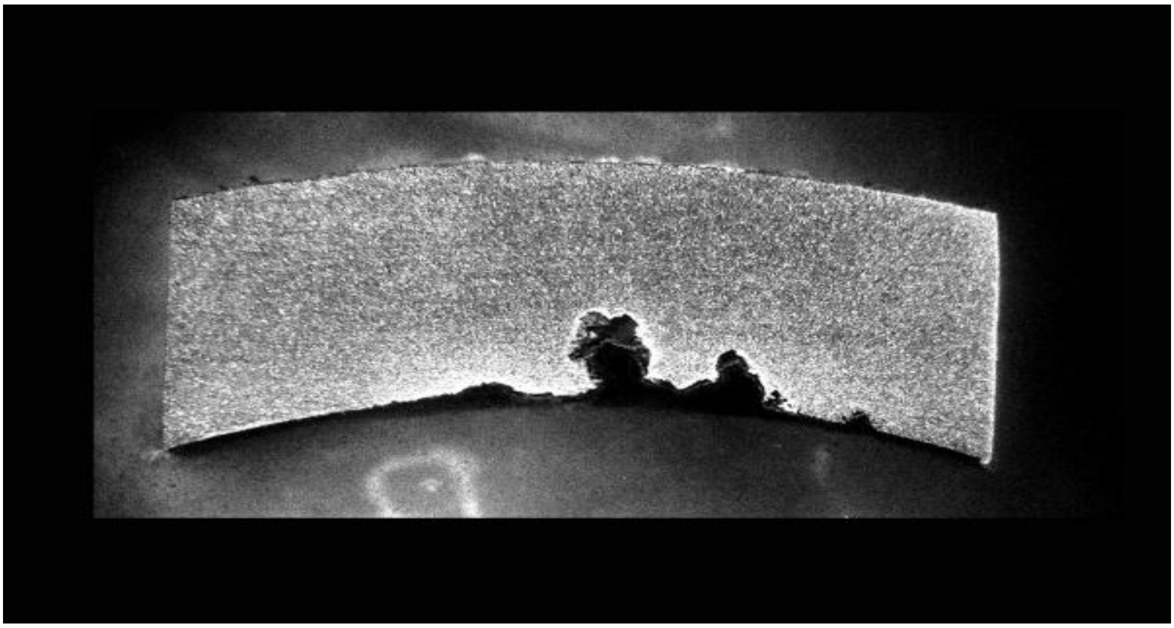

Figure 2-10: Pitting corrosion in boiler tube C [32]

Pitting corrosion can lead to more severe corrosion mechanisms such as intergranular corrosion, stress corrosion cracking and fatigue corrosion [33,34]. Figure 2-11 depicts a fatigue crack, which initiated at the bottom of a pit [35].

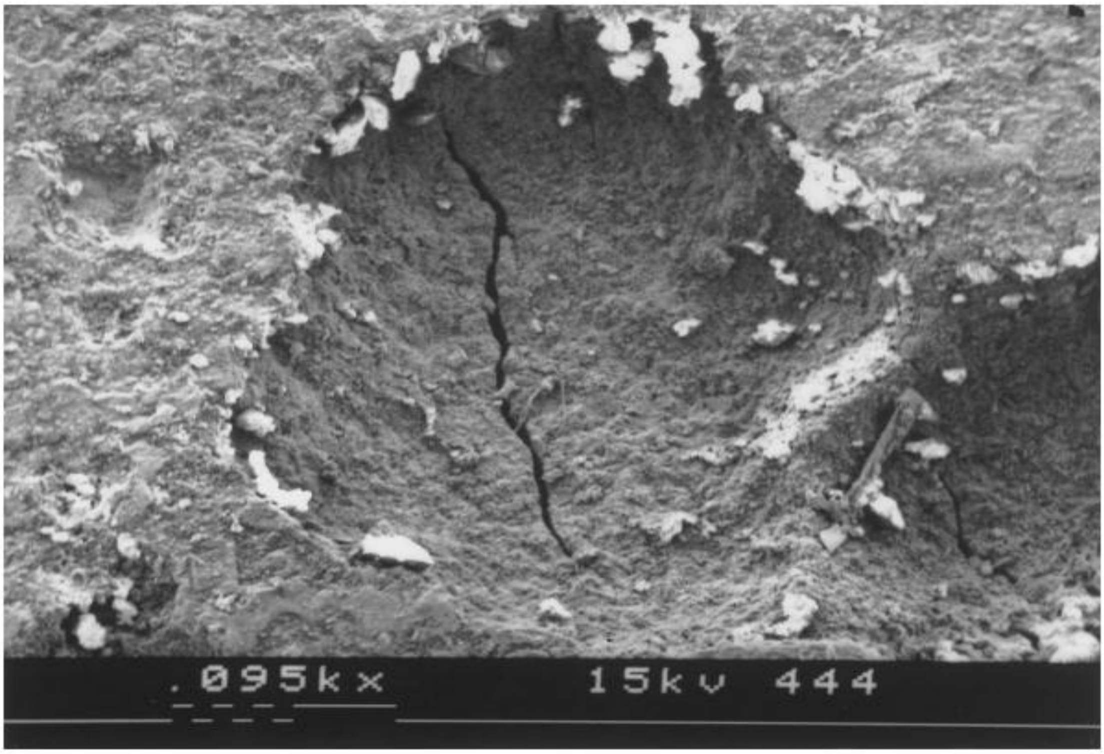

Figure 2-11: Fatigue crack initiated at the bottom of a pit [35]

Pitting corrosion comprises the initiation phase and the growth phase [9,36]. A surface scratch or a defect in the metal can cause the initiation phase of the pit [30]. With pitting and similar crevice corrosion the initiation phase involves the breakdown of the normal passive film (Fe_3O_4) formed under normal operation on the metal surface [37]. The chloride ions present (even in trace amounts) in the water causes the breakdown of the passive layer [38]. Dilute sulphate solution can also attack the passive layer to initiate the pit growth. During normal operation of the boiler, steam flows through the tubes and pitting will not form under normal operation. However, if the steam is not evacuated from the tubes and the tubes dried, condensation will occur and the tubes will be wet. This provides the environment in which pitting can be initiated. Other forms of passive film breakdown can be [29]:

- Straining of the substrate metal
- Differences in thermal expansion that cause thermal stresses
- Fluid flow and cavitation
- Transpassivity polarization
- Chemically induced phenomena

Under passive conditions oxide layers form naturally on the surface of metals which reduce the rate of corrosion of the metal [30,39]. The passive layer forms on the surface of the metal and degrades into the environment. At steady state, the passive layer formation equals that of the degradation. The point defect model (PDM) which is commonly used to describe the formation of pitting is outlined schematically in Figure 2-12 [29].

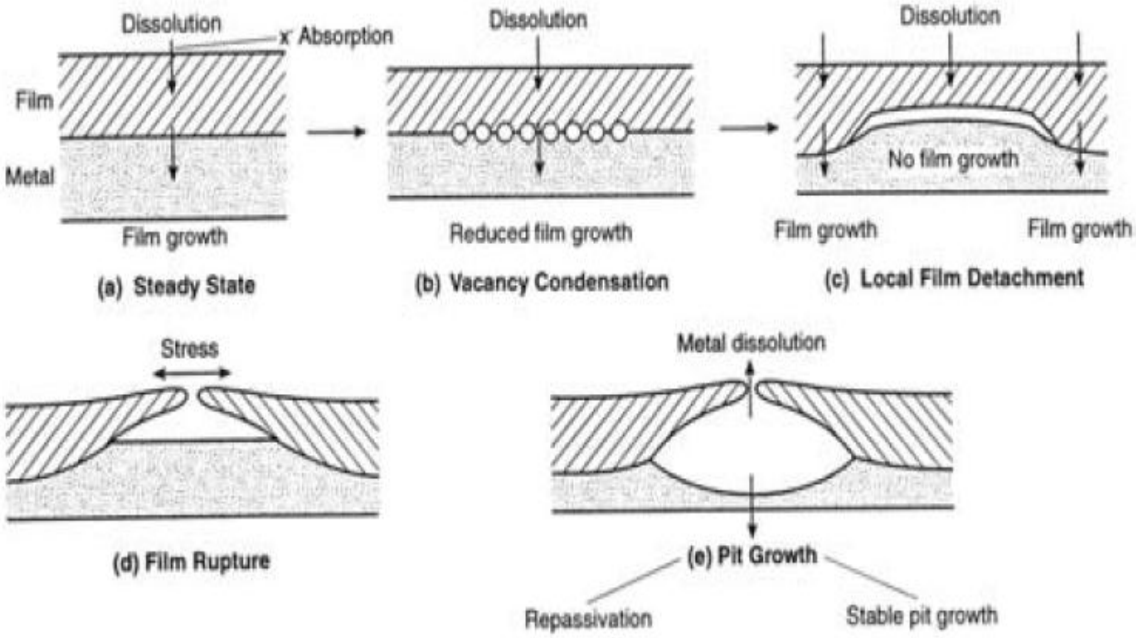

Figure 2-12: Schematic indicating the initiation phase as per the Point Defect Model [29]

The equilibrium of the metal and passive oxide layer is shown in Figure 2-12a. When one of the mechanisms mentioned above disrupts the equilibrium, the rate of dissolution is higher than the rate of formation resulting in a void forming between the metal and the passive oxide layer (Figure 2-12b and Figure 2-12c). Once this void exists between the metal and the passive layer, a further strain will lead to a rupture in this protective layer exposing the metal surface (Figure 2-12d). The metal is now exposed to the aggressive environment for direct corrosion and the growth of a pit. Metal dissolution will take place as the oxidation reaction, while the reduction of oxygen to form OH^- as the reducing reaction. These reactions are shown below in Equation 1and Equation 2 [30,31].

Equation 1: Oxidation reaction of metal

$$M \rightarrow M^{+1} + e^- \text{...}[1]$$

Equation 2: Reduction reaction of oxygen

$$\tfrac{1}{2} O_2 + 2H^+ + 2e^- \rightarrow H_2O \text{..}[2]$$

If the environment becomes less aggressive, the re-passivation of the metal surface can occur (Figure 2-12e) [29,30]. Aerated moisture is a key to pit formation and the addition of salts accelerates the corrosion [34]. Other models used to describe the pit initiation phase are the Penetration Mechanism, Adsorption Mechanism and the Film Breakdown Mechanism [29] and are discussed by Nuñez [40] and Frankel [39].

Those surfaces, which do not re-passivate will corrode and can be independent of the external environment. The environment within the pit supports itself and corrosion becomes autocatalytic [29]. Figure 2-13 depicts the autocatalytic process occurring in a corrosion pit [30].

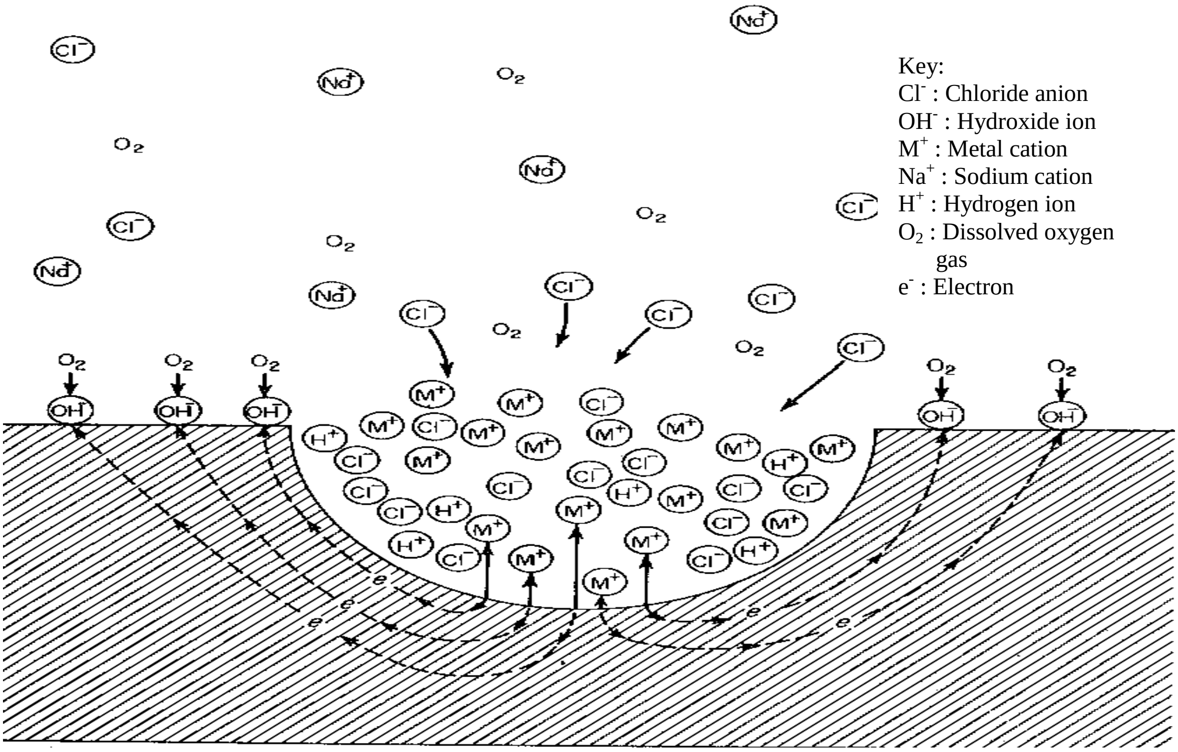

Figure 2-13: Autocatalytic processes occurring in corrosion pit [30]

It can be seen from Figure 2-13 that dissolution of metal M takes place within the pit while oxygen reduction takes place at the adjacent surface. With the dissolution of the metal a high concentration of positive ions exist, thus to maintain electro neutrality the chloride ions move into the pit. The H^+ ions from the hydrolysis and the Cl^- stimulate more metal dissolution thus increasing the depth of the pit [30].

Pitting is a form of corrosion that can occur throughout the boiler because of stagnant oxygen rich water within the tubes [41]. Pitting can occur on the outside of the tube when ash particles fuse to the metal creating an environment for pits to form [42,43]. In steam touched (Superheater and Reheater) tubes three causes of pitting can exist on the steam side of the tube. The first is because of poor shut down practices. The steam from operation is not evacuated sufficiently, resulting in the condensation of this steam, which forms pools of oxygen rich water in the low-lying areas or pendant loops/U-bends of the tubes. The second cause is from the mechanical carryover of Ca/Na_2SO_4 in the steam during operation, which deposits onto reheater tubes and then combines with condensate from shut downs thus leading to pitting. The third cause is from chemical cleaning damage in the superheater and reheaters which can also lead to pitting [9,10,37, 44-46].

Figure 2-14 [12] depicts a typical fossil-fired boiler convective pass. The hanging pendant tubes of the secondary reheater can be seen as well as the horizontal tubes of the primary reheater. These are indicated by A and B respectively.

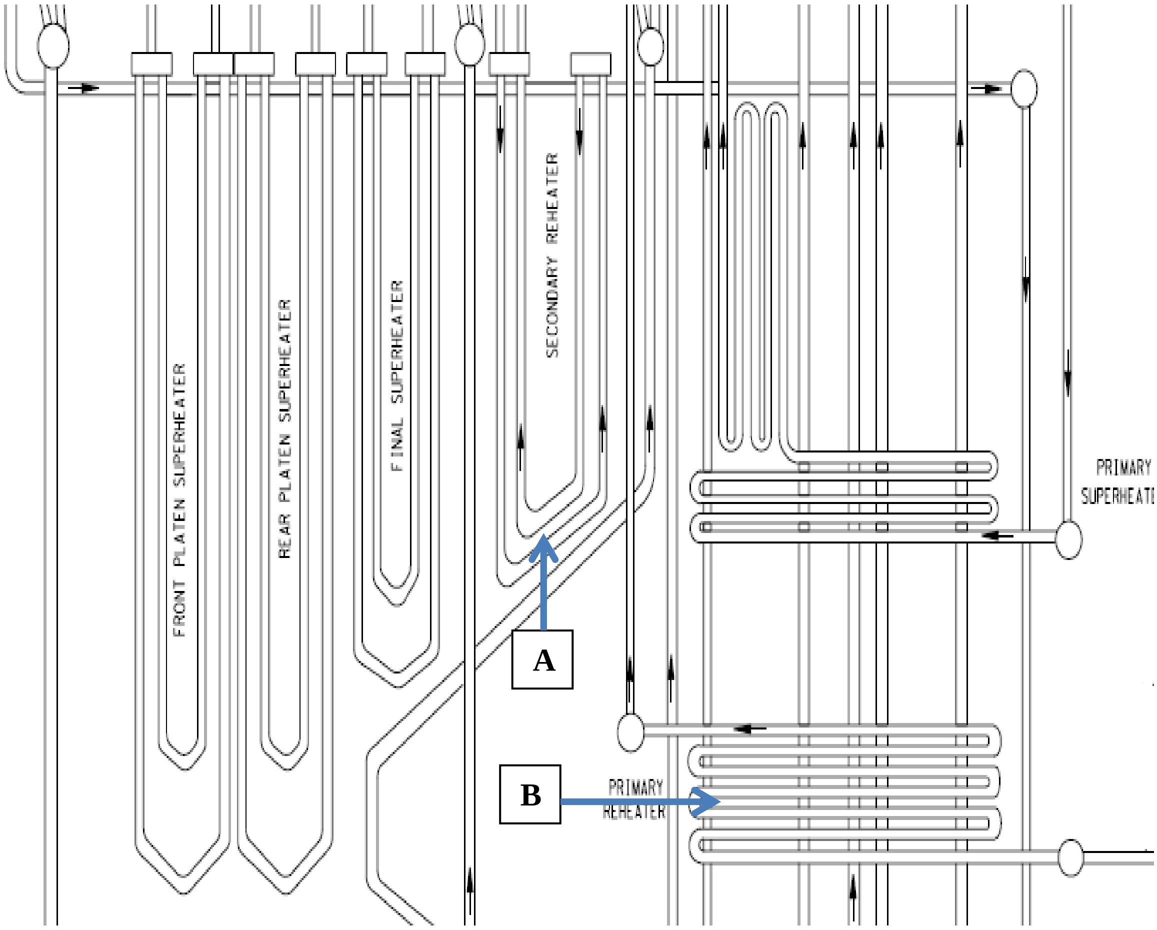

Figure 2-14: Drawing of boiler convective pass [12]

If during shut down the steam is not evacuated completely, it will condense and collect in the loops of the pendant tubes and any low-lying areas of the horizontal tubes. As discussed, above this oxygen rich stagnant water will cause pitting in these areas. Effective shut down procedures are required to ensure the drying of the tubes, to avoid any condensation during the outage [9]. Figure 2-15 and Figure 2-16 show boiler tubes subjected to pitting corrosion. Figure 2-16 is by courtesy of Eskom Holdings SOC Ltd and shows through wall pitting corrosion.

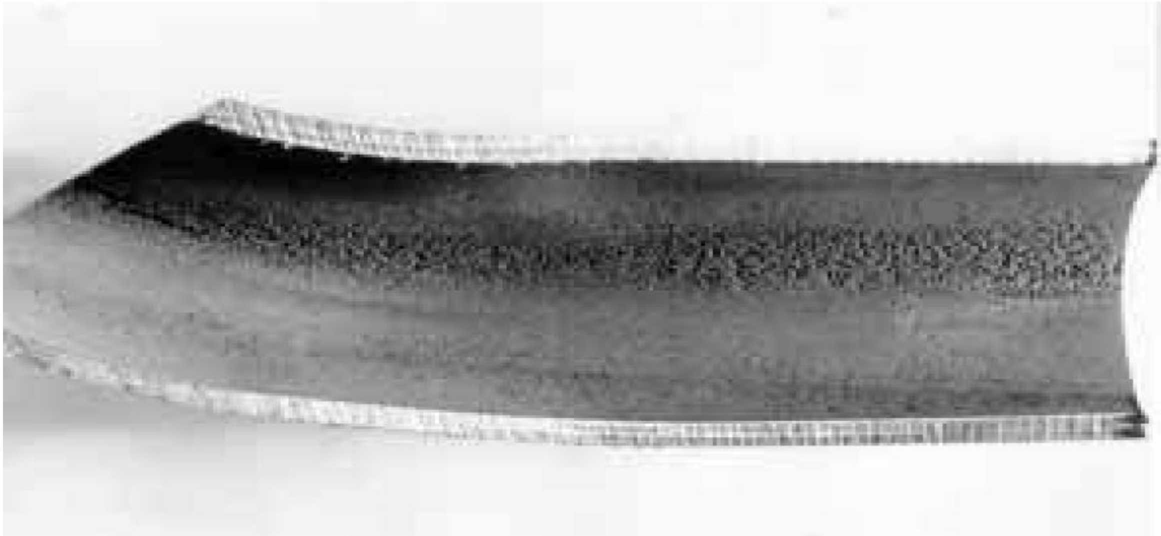

Figure 2-15: Internals of a superheater tube subjected to pitting corrosion [9]

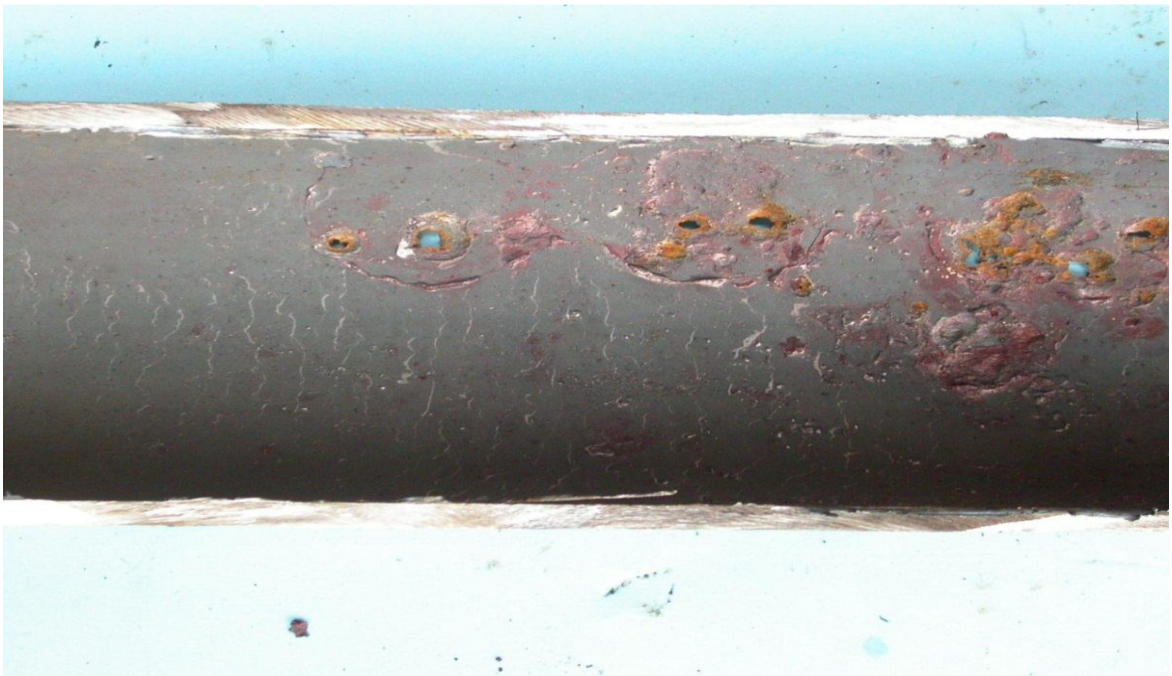

Figure 2-16: Primary reheater tube subjected to pitting corrosion [47]

2.4 Boiler Shut Down and Lay-up

In order to protect the equipment, effective procedures are required for the shutdown of the plant and for the lay-up or storage of the plant during the outage times. The aim of these procedures is to protect the equipment from off-line corrosion thus reducing the number of BTF's [48]. If ineffective procedures are followed for the shut down and lay-up of the plant, water can pool within the tubes, which will result in, pitted tubes. These pitted tubes can become through wall corroded, resulting in leaks or can initiate more serious mechanisms of tube failures as discussed earlier [34,48].

According to EPRI [34,48], shut downs can be classified into the following:

- Short-term Shut down (Wet)

This is an overnight or weekend shut down where the boiler is kept within normal operating temperature range.

- Intermediate Shut down (Wet or Dry)

This shut down is for periods longer then a weekend and up to a week. This could be for some equipment repair. In wet conditions, the boiler water chemistry is maintained as per normal operating conditions. In dry conditions, the boiler is drained and tubes are purged. Nitrogen can be used to blanket the tubes, however if work is to be done on the tubes the nitrogen must be removed for safety reasons.

- Long-term Shut down (Wet and Dry)

This is when the unit is out of service for more than a week and can be due to major equipment repair and maintenance during a general overhaul (GO) or for mothballing of a unit. In wet conditions, hydrazine concentrations are elevated and the pH is maintained above 9. Nitrogen is filled and pressurised to avoid air in leakage. In dry conditions, the boiler is drained while still hot and pressurised nitrogen blanketing can be used, alternatively dehumidified air can be circulated through the system.

- Forced Shut down

A forced shut down can be due to a system failure or major equipment failure. System failures generally result in short-term shut downs however, equipment failure results in a rapid shutdown of the plant and the lay-up would generally be classified as long-term.

The dry layup of the plant requires the drainage of the boiler, during the shutdown process, while the boiler is in a hot condition [9,34,48-50], i.e. to prevent the steam from condensing inside the tubes. Thereafter, layup of the boiler with either an inert gas or the circulation of dehumidified air is done to protect the surfaces from corrosion. EPRI [48] provides guidelines for the shut down and layup of the boilers in long and short-term periods. Boilers should be blanketed with steam or nitrogen during short-term layups. Table 2-2 extracted from EPRI [9,48] shows the advantages and disadvantages of the alternate methods of storing/preserving the boiler during layup conditions.

Table 2-2: Shut down and layup alternatives showing advantages and disadvantages for each alternative [9,48]

Layup Type	*Advantages*	*Disadvantages*
Wet Storage with ammonia/hydrazine solution*	1. No concern about relative humidity 2. Easily maintained 3. Easily tested 4. With proper insulation, leaks can be easily detected 5. Superheaters and reheaters can be stored/preserved safely 6. If facilities are installed, solution may be reused	1. Possible pollution when draining 2. Need to recirculate regularly 3. Hydrazine possible carcinogen 4. High water consumption prior to start up: solution must be drained and possibly rinsed 5. Regular monitoring 6. Excessive ammonia must not be added if copper alloys are present in the system 7. Tight isolations are prerequisite 8. Not recommended if freezing may occur 9. Draining if work is to be carried out 10. Pure water (demin) must be used
Nitrogen	1. System need not be completely dry 2. Completely independent of climatic conditions 3. May be used as a capping of normal operating fluid during outages	1. Very dangerous asphyxiation of workers if not properly vented before access 2. Preferably to be carried out while system is being drained
Dry air	1. Readily available basic constituent 2. Maintenance on plant	1. Drying equipment and blowers required 2. Climatic conditions may cause

* **Requires nitrogen**	performed without problems 3. Easy monitoring 4. No risk to personnel 5. Whole plant may be stored/preserved dry if drainable or dryable 6. Independent of ambient temperature if air dry enough 7. Residual heat in boiler steelwork utilised for drying	rapid deterioration in storage conditions 3. Hermetical sealing may be required to prevent 2, above 4. System must be completely dry 5. Sediment may cause corrosion if hygroscopic 6. SO_2 and dust must be excluded from the air 7. If work to be carried out on part of dried system, that part of system must be isolated and redried afterwards 8. Even draining while hot and under pressure does not ensure complete water removal

(Table extracted from EPRI guidelines [9,48])

Dry storage using dehumidified air is growing in popularity in the USA for long- and short-term layup periods [44,48]. Figure 2-17 is the justification behind storing the boiler in low humidity conditions. The figure shows the corrosion rate of steel relative to the humidity of the air. It is clear that if the humidity of the air is kept below 60% the corrosion rate is low thus protecting the tubes from significant off-line corrosion. The units of corrosion rate were not reported by the source, however emphasis is placed on the change in corrosion rate above 60% relative humidity.

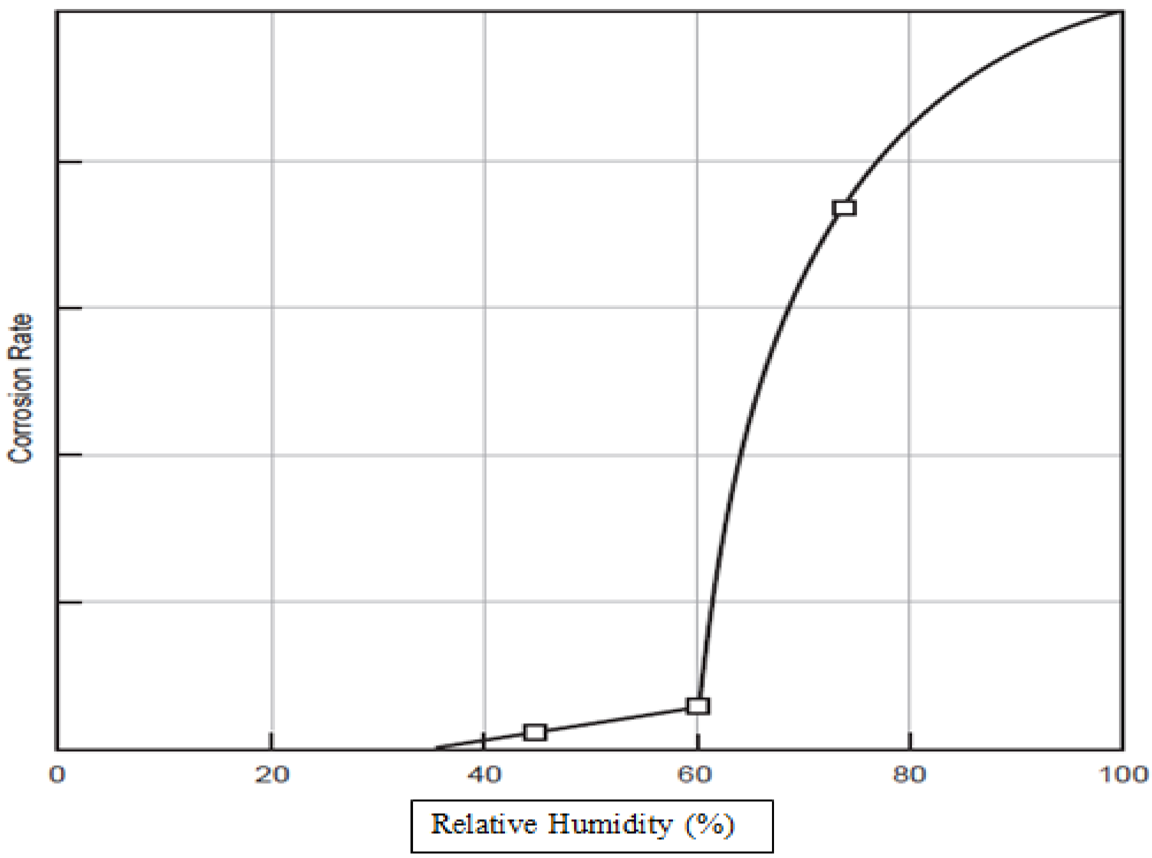

Figure 2-17: Corrosion rate of steel vs. relative humidity of air [48]

Figure 2-17 looks at the effect of humidity on off-line general corrosion. To ensure that pitting corrosion does not occur, pooling or condensation within the tubes should be avoided. This will be achieved by drying the tubes to a point where the dew point is lower than the coldest ambient conditions that the tubes will experience during the shutdown period. Matthews [34] mentioned that the preferred method to achieve dry tubes is by making use of compressed air to force the steam out during the shutdown process and thereafter-making use of one of the lay-up methods discussed in Table 2-2. A flow diagram for the circulation of the dehumidified air can be seen in Figure 2-18 [48].

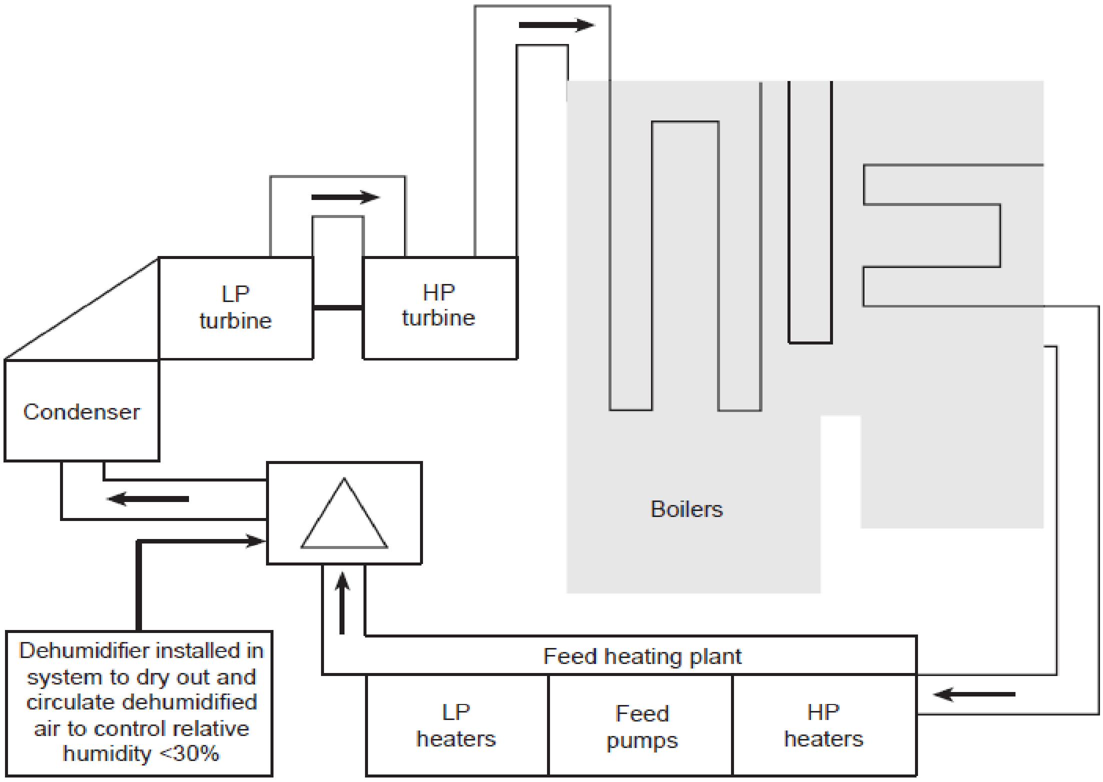

Figure 2-18: Block diagram showing dehumidified air circulation in boiler steam/feed cycle [48]

Where:

LP: Low pressure

HP: High Pressure

As mentioned, the use of dehumidified air during the layup period requires the draining off and drying of the system. This can be a difficult task especially for the hanging pendant loops of superheaters and reheaters [48]. Drying is accomplished by either forcing the steam out using pressurised air or sucking the steam out by making use of the condenser vacuum [11]. Vacuum drying takes 10 – 36 hours to reach completion [48]. The boiler needs to be flash drained at 1.7MPa (corresponding to 204.31°C saturation temperature) drum pressure to prevent condensation in the superheater and reheater U-bends and hanging pendant sections [48].

Cargocaire [51] describes how one power plant effectively used dehumidified air from the layup of the boiler. Best results are attained by effectively removing all liquid water from the system. This was achieved by draining the boiler at 20.7MPa and then at 4.1MPa applying nitrogen to prevent any oxygen ingress. After the water was drained, the oil burners were fired to maintain the temperature at 232.2°C. The fire remained until there was no perceptible vapour emerging. Each of the low points were vacuumed and mopped and in some cases, pipe sections were removed to allow water to flow out. Thereafter, dryers were placed in service, and dehumidified air circulated through the system maintaining low relative humidity.

2.5 Conclusion to the Literature Review

The operations of a coal-fired power station were discussed with the major equipment being shown and described. Boiler tube failures are the highest cause of plant UCLF. Pitting corrosion is one of the mechanisms which lead to boiler tube failures. Pitting corrosion occurs because of oxygen-saturated water laying in the pendant loops and low-lying areas of superheaters and reheaters. Pitting corrosion can only occur when there is water present. There are guidelines for the storage of the boiler and the literature has shown that the boiler needs to be drained while still hot in order for the layup methods to be effective. The literature surveyed from the EPRI reports has not given a guide on which method of draining the boiler is most effective during the shutdown. This research will show from the three methods of reheater drying which is the most effective. Chapter 3 describes at the experimental set-up used for determining the effectiveness of the reheater drying during shut down.

CHAPTER 3: EXPERIMENTAL PROGRAMME

3.1 Introduction

Chapter 2 discussed the operations of a fossil-fuelled power station and failures concerning boiler tube leaks. The aspects of pitting corrosion were covered and guidelines for preventing off line corrosion through effective shut down and layup procedures were discussed. This chapter deals with testing the effectiveness of three reheater drying procedures.

The method of testing the effectiveness of the drying procedure is to determine the moisture content at the end of the drying. Relative humidity and dry bulb temperature measurements will be taken at the outlet flow of the drying process at seven different power stations using one of the different methods. Dew point temperature is calculated using Equation 3 [52].

Equation 3: Dew point Temperature

$$Td = T\left[1 - \frac{Tln\left(\frac{RH}{100}\right)}{\frac{H_{vap}}{R_w}}\right]^{-1}$$

Where:

R_w is the gas constant for water vapour ($461.5JK^{-1}kg^{-1}$)

H_{vap} is the enthalpy of vaporization

(H_{vap} = 2501 $KJ.kg^{-1}$at T = 273.15 K and H_{vap} = 2257 $KJ.kg^{-1}$ at T = 373.15 K)

Three methods of drying used at seven different power stations will be tested for its effectiveness.

3.2 Comparison of Power Stations

Table 3-1 provides a comparison of the seven power stations tested.

Table 3-1: Comparison of power stations

Power Station	**A**	**B**	**C**	**D**	**E**	**F**	**G**
Power Generated (Gross MW)	640	619	630	396	585	575	625
Auxiliary Power (MW)	46	25	50	20	24	25	25
Boiler Type	Drum	Once Through	Once Through	Drum	Once Through	Drum	Drum
Boiler Layout	2-pass	Tower	Tower	2-pass	Tower	2-pass	2-pass
Elevation (m)	1581	1582	872	1765	1629	1586	1470
Reheat Pressure (MPa)	3.80	3.65	3.70	3.70	3.6	3.94	3.80
Reheat Temperature (°C)	535	535	535	510	535	535	535

Table 3-1-Continued

Power Station	**A**	**B**	**C**	**D**	**E**	**F**	**G**
Reheater Tube Outer Diameter (mm)	63.5	50	44.5-63.5	47.63	50	55.5-63.5	55.5-63.5
Reheater Tube Wall Thickness (mm)	3.378 – 3.785	3.6	3.6-4.9	4.1-4.3	3.6	4.3-4.7	4.3-4.7
Reheater Volume (m^3)	360	170	298	70	170	199	289
Age (years)	20	32	25	41	25	31	28
Drying Method	Forced Compressor (1 MPa (g) 200m^3/min)	Vacuum	Boil	Forced Compressor (500 kPa (g) 20m^3/min)	Forced Compressor (250kPa (g)120m^3/min)	Vacuum	Vacuum

The power stations where testing was done are all over 20 years of age. There are two types of boilers used namely once through tower boilers which have horizontal tube banks while the drum 2-pass boiler type has horizontal tube banks as well pendant loops. Vacuum and forced drying is used in both types of boilers while boil drying is only used in Power Station C. All the stations are base load stations, which are similar in generating power with the exception of Power D, which is 200MW below the rest. Power Station D is also the oldest power station from the seven. Power Station D operates with a hot reheat temperature of 510°C while the rest of the stations operate at a temperature of 535°C. The hot reheat pressures range from 3.6 – 3.94 MPa. For all power stations under normal boiler shut down, the reheat pressure drops to 0 before reheater drying commences making the conditions inside the reheater at the beginning of reheater drying the same. All power stations have similar altitudes as they are in the Highveld of South Africa with the exception of Power Station C situated in the Lowveld of South Africa.

Power Stations B and E have different generating power due but have the exact same boiler design and layout. The boiler tube dimensions are exactly the same, however Power Station B makes use of vacuum drying while Power Station E makes use of forced drying with a compressor delivering 250kPa (gauge) maximum pressure with an air intake of 120 m^3/min.

The three different drying procedures are discussed next.

3.3 Reheater Drying Procedures

Reheater Drying Procedures

The steam flow diagram is shown in Figure 3-1.

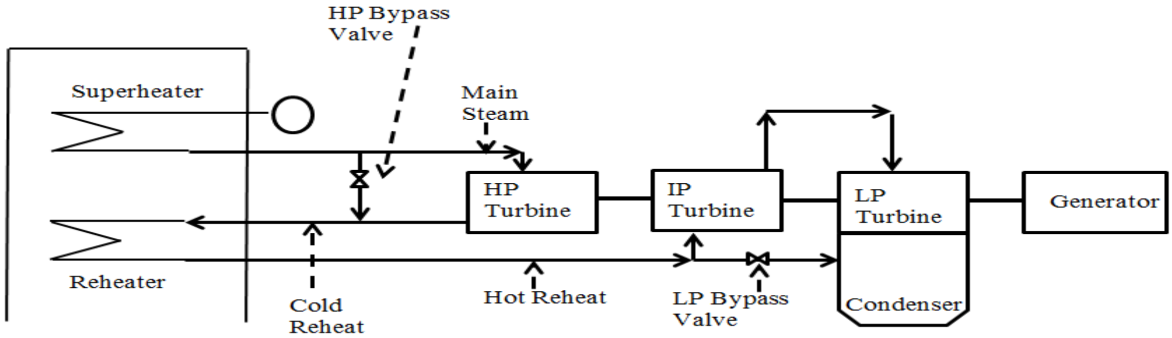

Figure 3-1 : Steam flow diagram

Saturated steam from the evaporators enters into the superheater to form superheated steam. The superheated steam called *main steam* goes to the HP turbine. Steam leaving the turbine known as *cold reheat* enters the boiler reheat tubes and leaves the boiler as *hot reheat*. The hot reheat enters the IP turbine. Steam leaving the IP turbine flows directly to the LP turbines. It then leaves the LP turbine and flows into the condenser to be condensed. An HP bypass valve allows the steam to be directed into the cold reheat pipes bypassing the HP turbine. The LP bypass valve allows steam from the hot reheat pipe to bypass both the IP and LP turbine and flow directly into the condenser.

The three methods of reheater drying are 1) forced, 2) vacuum and 3) boil drying. The three methods are discussed below:

3.3.1 Forced Drying

Forced drying makes use of compressed air to force the steam within the reheaters out and replace it with air, immediately after shut down. Figure 3-2 depicts the flow diagram of the forced drying process. A summary of the procedure used at Power Station A is given below [13].

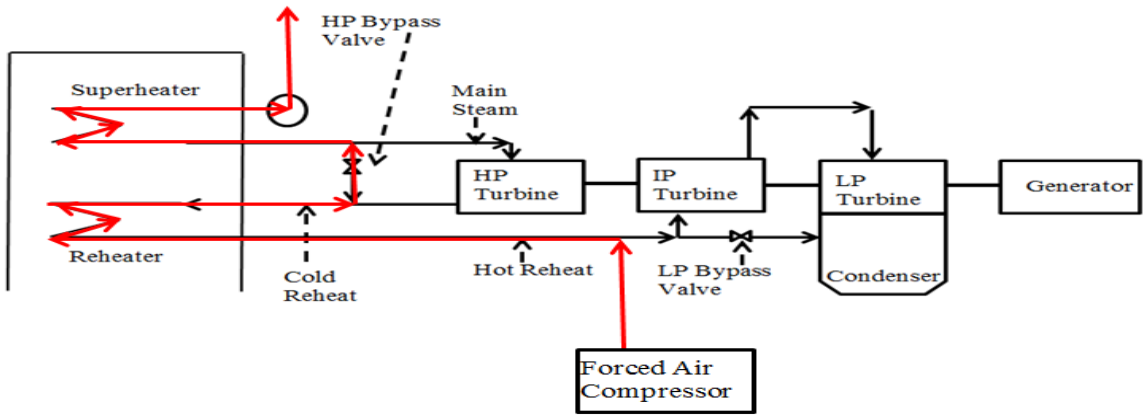

Figure 3-2: Forced drying flow diagram

Prior to reheat drying the unit needs to be shut down according to the shutdown procedure [13]. This includes:

1) Deloading of the boiler

2) Emptying of the mills,

3) Reducing steam pressure with HP and LP bypass valves open,

4) Opening of drain valves to drain into the blow down vessel,

5) Purging of the boiler once fires are out and
6) Boxing of the boiler.

Boxing of the boiler essentially closes the gas flow into and out of the boiler, once purging is completed. This is to ensure that no cold air enters the boiler and the boiler tubes remain hot. During the shutdown of the boiler, the forced air compressor is started and the common line from the compressor to all the units is drained and dried. After 1 hour of drying the common line, the drain valves are shut in preparation to dry the reheat and superheat tubes. This particular power station is equipped with a 1MPa compressor which delivers a final output pressure into the pipework of approximately 800kPa.

Reheater and superheater drying commences once the main steam pressure is at 200kPa. Compressed air is supplied for drying of the reheaters and superheaters at the IP turbine side. The HP and IP turbine governor valves and LP bypass valve remains shut so that no air flows through the HP turbine, IP turbine and condenser. Air flows in the reverse direction compared to normal steam operation. Air flows into the hot reheat pipe, into the reheaters, through the HP bypass valve into the superheaters, and is exhausted out of the superheater drains to the blowdown vessel. This is depicted by the red line in Figure 3-2.

Once the air flow rate is maintained at 190kg/min, measured by an installed flow meter, the boiler can be forced-cooled by starting up the secondary air fans and opening the dampers to allow cold air to enter the boiler and cool the boiler down. Approximately half the mass flow enters the reheaters. Drying of the reheaters is terminated by shutting the air supply valves when the air heater gas outlet temperature has cooled to 60°C. Boiler forced cooling continues until the boiler has cooled to an acceptable temperature to continue with any maintenance work required within the boiler.

The other power stations making use of forced drying have a similar procedure. The compressor connection to the reheater are slightly different with Power Station D connecting directly to the HP turbine casing (portable compressor) and air flows through the cold reheat into the reheaters, out of the hot reheat pipe and exhausts out of a vent. Power Station E has a dedicated compressor connecting between the ESV and GV. Air flows through the cold reheat pipe, through the reheater circuit, out of the hot reheat pipe, through the LP bypass valve and exhausts into the condenser.

3.3.2 Vacuum Drying

Vacuum drying makes use of the condenser vacuum to draw the steam out of the reheater tube and replace with air entering from an air inlet valve. Figure 3-3 depicts the flow diagram of the vacuum drying process. A summary of the procedure used at Power Station B is given below [14] with similar procedures for Power Station's F and G.

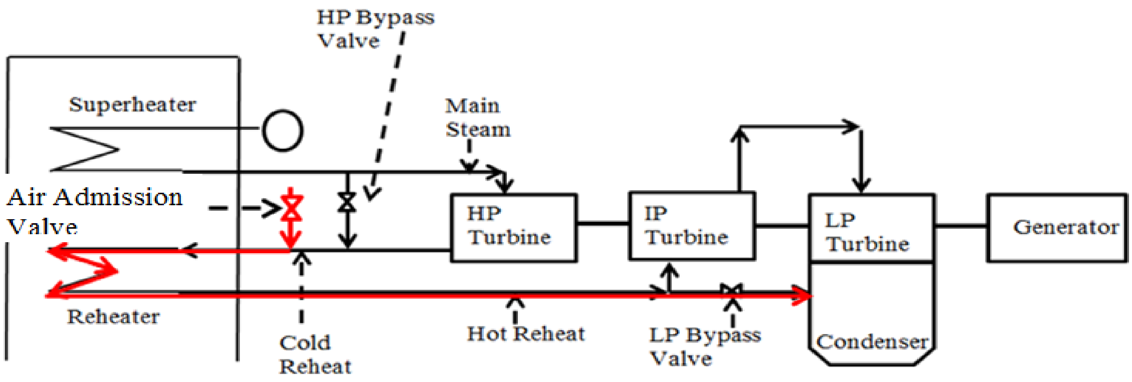

Figure 3-3: Vacuum drying flow diagram

As discussed before, prior to reheater drying the boiler must be shut down. The HP bypass valve must be closed to isolate the reheater from the main steam. The pressure in the reheaters is allowed to decay via the LP bypass valve. The boiler is boxed until after reheater drying is completed. The drying procedures at Power Stations F and G allow for boiler forced cooling before reheater drying is completed Steam Air ejectors are used to maintain a vacuum within the condenser. Once a vacuum is established and maintained at -10 to -15kPa the air admission valve must be opened to allow air into the reheaters. Air enters the air admission valve, into the cold reheat, flows through the reheater tubes, out the hot reheat pipe through the LP bypass valve and is exhausted through the condenser. Vacuum drying terminates after 2 hours of steam ejectors running. The LP bypass valve is closed and the pressure allowed to increase to atmospheric pressure through the air admission valve [14]. This method does not dry the superheaters as with the forced drying procedure. The key difference between Power Station A and Power Station B is the forced drying method used by Power Station A which delivers a high air flow rate achieved by the compressor to dry the reheaters and additionally dry the superheaters.

3.3.3 Boil Drying

Boil drying makes use of heat energy from burning fuel oil to boil out any condensate which has formed inside the reheater tubes. Figure 3-4 depicts the flow diagram for the boil drying process. A summary of the procedure used at Power Station C is given below [15].

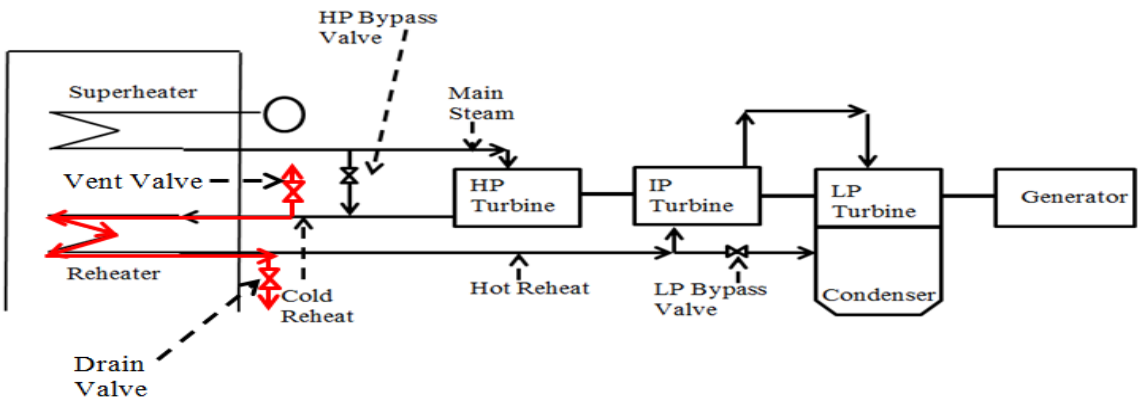

Figure 3-4: Boil drying flow diagram

After the unit is shut down, the boiler is forced-cooled with air before reheater drying commences. The LP and HP bypass valves are to remain shut. The reheat pressure naturally decays because of the force cooling. Once the reheat outlet pressure is at 0.4MPa, the drain valves are opened. At 0.3MPa the vent valves are opened. Reheater drying commences when the pressure is at 0.1MPa. The oil burners are then placed on high fire for 10 minutes to boil out any water remaining inside the reheaters. This completes the reheater drying and boiler forced cooling continues. The reheater vents and drains are shut after reheater drying has completed. Thereafter, turbine forced cooling takes place making use of a compressor connected to the HP turbine casing. The HP turbine is connected to the cold reheat piping, and with the vents and drains closed, the reheat circuit is pressurised.

3.4 Experimental Equipment, Set-up and Procedure

The investigation required an estimation of the properties of the fluid that will be exhausted (forced drying) or drawn (vacuum drying) from the test point during the tests for equipment selection. Using previous shut down data and consultation with power station operators and instrumentation engineers, the properties of the fluid were estimated and are given in Table 3-2.

Table 3-2: Estimated properties of fluid from test point

Drying Method	Pressure	Temperature
Forced	200kPa (abs) Based on compressor output pressure and taking into account pressure drop along the flow path	60°C – 120°C (Estimated Range) Based upon the closest temperature measurement and taking into account cooling through the pressure impulse line which is not insulated
Vacuum	6kPa (abs) Based upon the minimum pressure in the condenser	
Boil	200kPa (guage) Based on turbine force-cooling compressor output which pressurises the reheater	

The vacuum pump required for testing, needed to be portable and have sufficient suction to draw the fluid out of the reheater and deliver the fluid to the measuring (humidity) box. The effectiveness of the procedure is tested once the drying of the reheater is completed. Testing during the drying period indicates the rate of drying but is not a requirement. The Vaccutronics DP 200H portable vacuum pump was used and it is capable of drawing out fluid with temperatures within the required range. The performance curve for the vacuum pump is given in Appendix A. The pump cannot draw against the vacuum created in the condenser used during drying, but when reheater drying is completed, the vacuum in the reheaters is broken as the condenser ejector pumps are switched off, the pump draws against atmospheric pressure. During forced drying, the pressure at the test point should deliver sufficient flow thus the pump will not be required. Rubber and copper piping which can withstand the pressure and temperature was used. Pressure transducers connected to the reheat circuit provides direct access to the reheater tubes and are close enough to representatively measure the properties of the fluid therein and thus was chosen as the test point without the need to modify the plant for a special test point. Therefore, half inch fittings were used to connect the test equipment, as this was common to all power stations. Thread tape was used to ensure connections are tightly sealed and that no air enters the system and no reheater fluid leaks out. This was verified with a pressure test, pressuring with compressed air to 300kPa and observing any pressure decay on pressure gauge. All connections were checked for leaks with soap.

Figure 3-5 shows a schematic diagram of the equipment set-up. Valve (V1) is connected to the reheat circuit with a half inch BSP (British Standard Pipe) fitting. Fluid from the reheater will flow through (V1) where the temperature will be measured with a K-type thermocouple (T1). V2 and V3 are valves operated to direct the flow through the vacuum pump VP into the humidity box for dry bulb temperature and relative humidity measurements at T2 and RH (relative humidity), respectively. T2 and RH are measured by a Testo 635 humidity meter with a high temperature humidity probe inserted into a perspex box (humidity box). The Testo 635 measures relative humidity, temperature and calculates the dew point. Measurements are taken in the humidity box to avoid the effects of ambient air. Flow can be diverted away through V2 for the protection of the relative humidity meter in case the temperature of the fluid is above 120°C measured. During forced drying of the reheater the vacuum pumps is disconnected and flow goes from V1 direct to the humidity box. Flexible air hose and half inch copper piping were used as connector pipes. Figure 3-6 is a photograph of the equipment set-up.

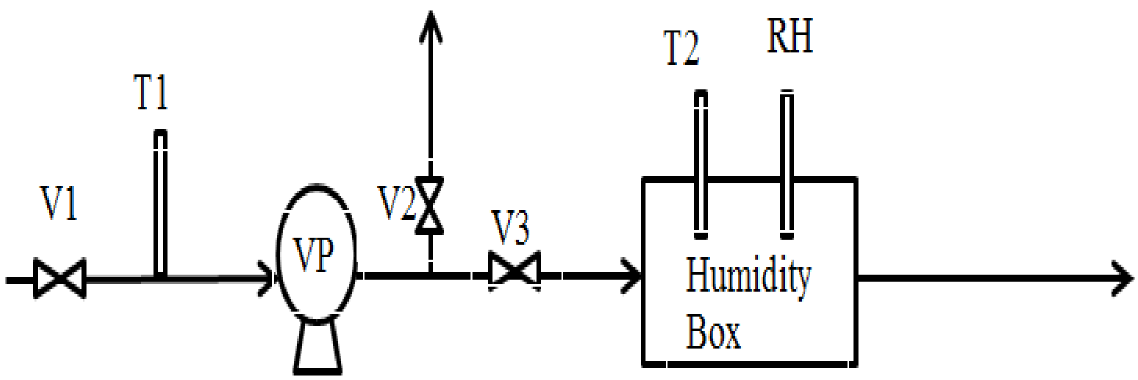

Figure 3-5: Schematic of equipment set-up

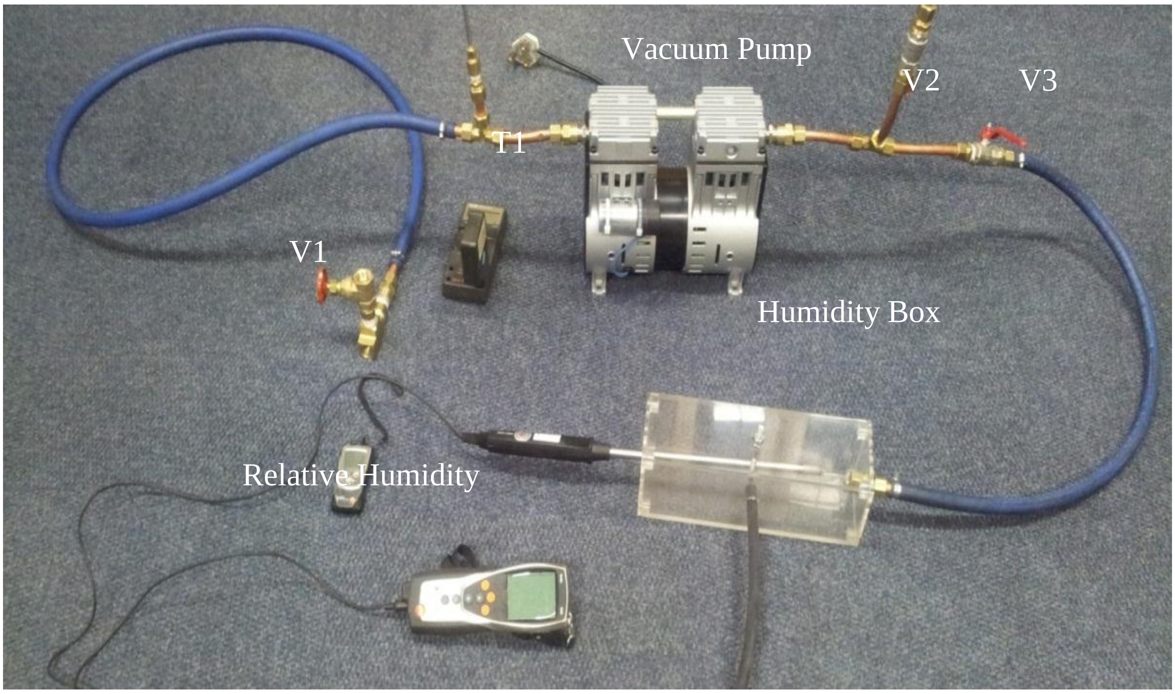

Figure 3-6: Picture of equipment set-up

3.5 Relative Humidity Test Procedure

At each of the power stations tested, a suitable test point was identified. The test points were at the outlet flow of the drying process. With the forced drying Power Station A the test point needed to be on the cold reheat pipe. The drain line from the cold reheat header had a test point installed previously. The test point is shown in Figure 3-7

Figure 3-7: Test point on cold reheat drain line at forced dried Power Station A

This test point needed to be cut and welded with a half inch male fitting in order to connect the humidity test equipment. The plant safety regulations required a permit to be issued in order for the cutting and welding of the test point. The permit is issued when main steam pressure is 0MPa(g) and there is no steam flow to the test point. This isolation is achieved by shutting the valve before the test point. Once the fitting is welded on and the equipment set-up the isolation valve is opened and steam allowed to flow to the test point.

The other six stations made use of pressure transducers as the test point. The pressure impulse line provides direct access to the reheat line and the standard fitting for transducers is a half inch BSP (British Standard Pipe) thread. Figure 3-8 shows the pressure transducer test point at Power Station B with a similar set up at Power Station C.

Figure 3-8: Pressure transducer test point at vacuum dried Power Station B

If required, the test lines were purged of any liquid build up in the line while there was still pressure in the impulse line or with compressed air from a nearby service line.

Temperature, relative humidity and the instruments calculated dew point are the three main measurements which were recorded. Dew point temperature was recalculated using Equation 3 as mentioned in Section 4.1. The ambient measurements were taken at the inlet of the processes, which is at the compressor inlet for forced drying and at the air inlet valve for vacuum drying. Measurements of the fluid flowing out of the test point commenced as soon as reheater drying started. This is termed a hot measurement. Measurements are taken while conditions are hot to avoid any condensation occurring and reflecting incorrect humidity measurements. Process data mentioned below were obtained from the station log books as well as the operator shut down log books detailing the shutdown.

a. Hot reheat temperature (as close to the reheater as possible) – this indicates the temperature of the hot reheat and monitors the temperature decay during the shutdown, in particular the temperature decay during force cooling or boiler boxing.
b. Hot reheat pressure (as close to the reheater as possible) – this identifies how long after the reheater is at 0 pressure does drying commence.
c. Condenser pressure – This provides information on the condenser vacuum.
d. Main steam pressure – Reheater drying commences when main steam pressure is 0.
e. Total Air Flow – This provides information relating to force cooling of the boiler.
f. Rotary Air Heater Gas inlet temperature – The air heater outlet temperature provides an indication of the temperature within the boiler environment. The air heater is the last piece of equipment inside the boiler and while cooling is taking place in the boiler the air heater temperature would represent the hottest fluid temperature.
g. Total Fuel Flow – this is the fuel oil and coal flow and indicates when the fires are out.

Chapter 4 provides the results obtained from three tests in detail. The results from the three drying methods used at the seven power stations are presented, discussed and compared. The remaining four power stations' detailed results are presented in Appendix C

CHAPTER 4: RESULTS AND DISCUSSION

Chapter 3 discussed the experimental set-up used in determining the effectiveness of the three drying procedures. The results obtained from the relative humidity testing conducted at three of the seven power stations each using one of the three drying procedures are presented in this chapter followed by a discussion comparing the seven power stations' drying results. Results for the remaining 4 power stations' with measured data is available in Appendix C.

4.1 Results

4.1.1 Forced Drying Test Results at Power Station A

The plant data for the shutdown, collected from the station log books, are presented below in Figure 4-1.

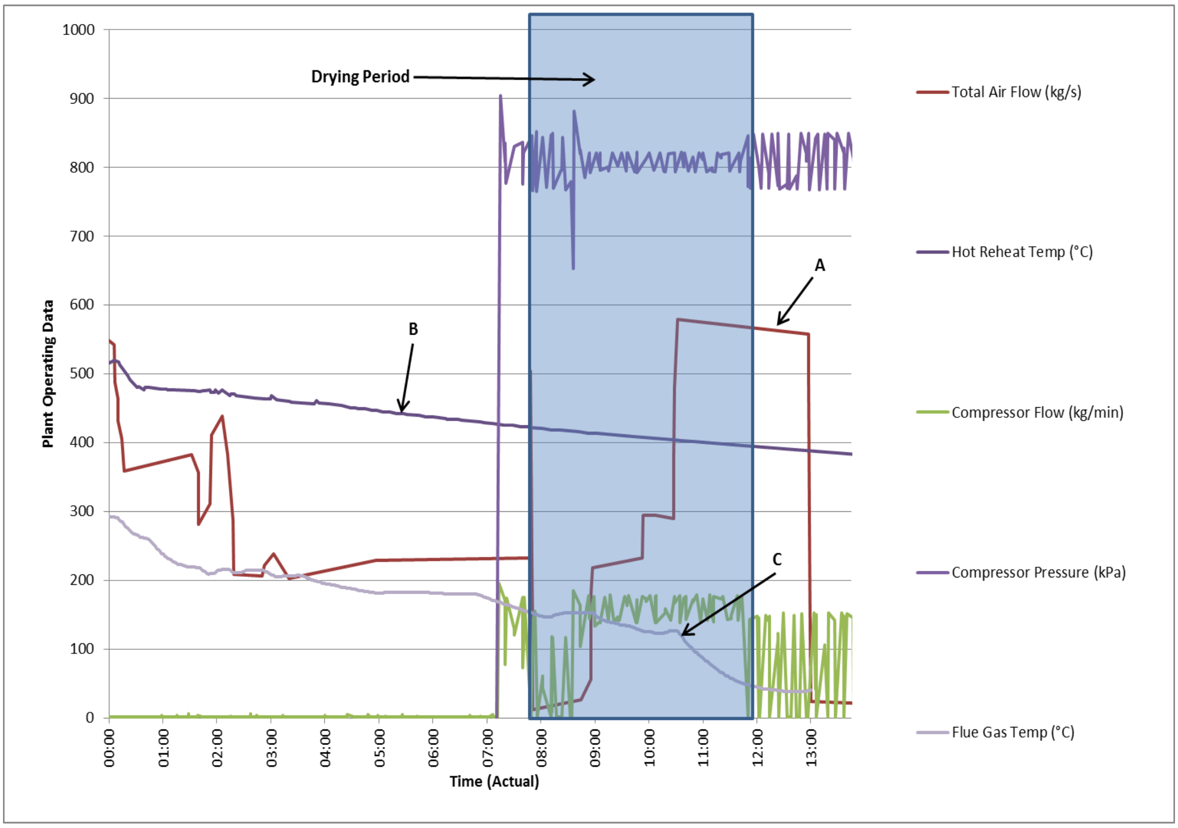

Figure 4-1: Force drying data from Power Station A

The blue shaded area in Figure 4-1 indicates the drying period which commences when main steam pressure is at 0 with the force cooling compressor drains are shut. According to the operator logs as shown on Table 4-1, this took place at 7:45am. At 8:30am the flow was maintained at 190kg/min and boiler forced-cooling commenced. This is indicated by the line marked A which represents the total air flow. During the drying period the hot reheater temperature marked B remained above 200°C. Flue gas temperature was above 100°C until 10:45am marked C. As mentioned before the flue gas temperature is a more representative indicator of the actual tube temperature in the boiler as compared to the hot and cold reheat temperature. This is because the hot and cold reheat temperature measurements are taken outside of the boiler, in the pipework close to the turbine which is insulated. The cooling effect of the cold air is not taken into account. Tubes in the boiler are much cooler due to the boiler cooling taking place.

Table 4-1: Operator logs for the forced drying test at Power Station A

No.	Time	Comment
1	7:30am	All boiler superheater vents open (Indicating pressure is zero)
2	7:38am	Pressure part permit to work issued (Allowing fitting to be welded to test point)
3	7:45am	Forced cooling compressor drains shut
4	8:30am	Force cooling in progress on boiler (Indicating drying has started)
5	8:45am	LH draught group in service, RH FD fan failed to start
6	10:30am	RH FD fan started (Indicating boiler is being force cooled)

The test commenced once the fitting was welded to the test point. This was approximately one hour after drying had begun due to issuing of permits required for cutting and welding of the test point. Results are shown in Figure 4-2.

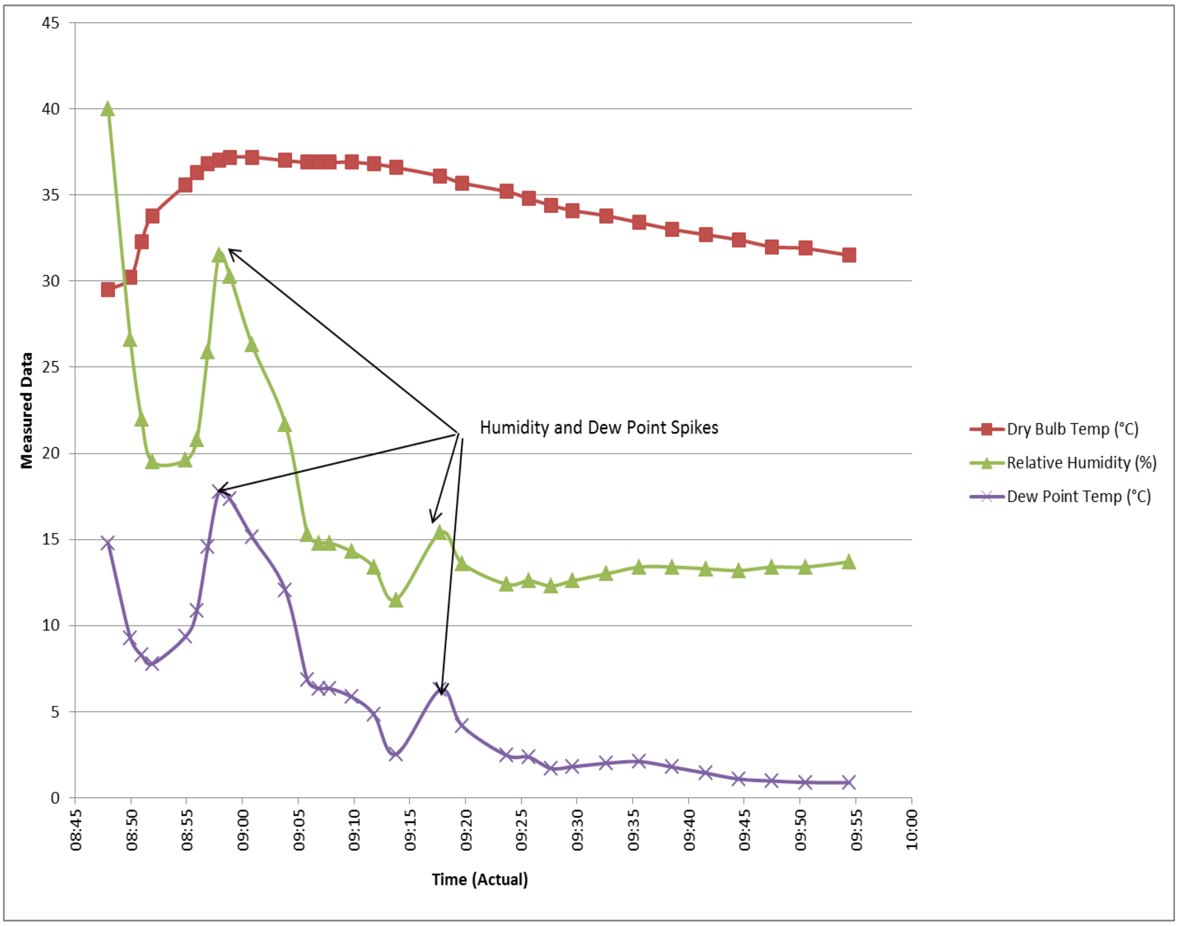

Figure 4-2: Force drying test results at Power Station A

It can be seen that as drying progressed the relative humidity and dew point decreased. At just over two hours of drying the relative humidity measured coming out of the test point was 13.7% at 31.5°C. The dew point calculated is 0.9°C. The ambient conditions were measured to have a relative humidity of 47% at 29.2°C with a dew point of 17.3°C. The high pressure air form the compressor removes some of the moisture in the air as liquid and discharges this liquid. The air is then heated in the pipe network of the boiler before entering the reheater thus increasing its moisture carrying capacity. There are two spikes in the relative humidity and dew point measurements which will be discussed later in Section 4.3.1.

4.1.2 Vacuum Drying Test Results at Power Station B

The plant data for the shutdown, collected from the station logs, are presented below in Figure 4-3.

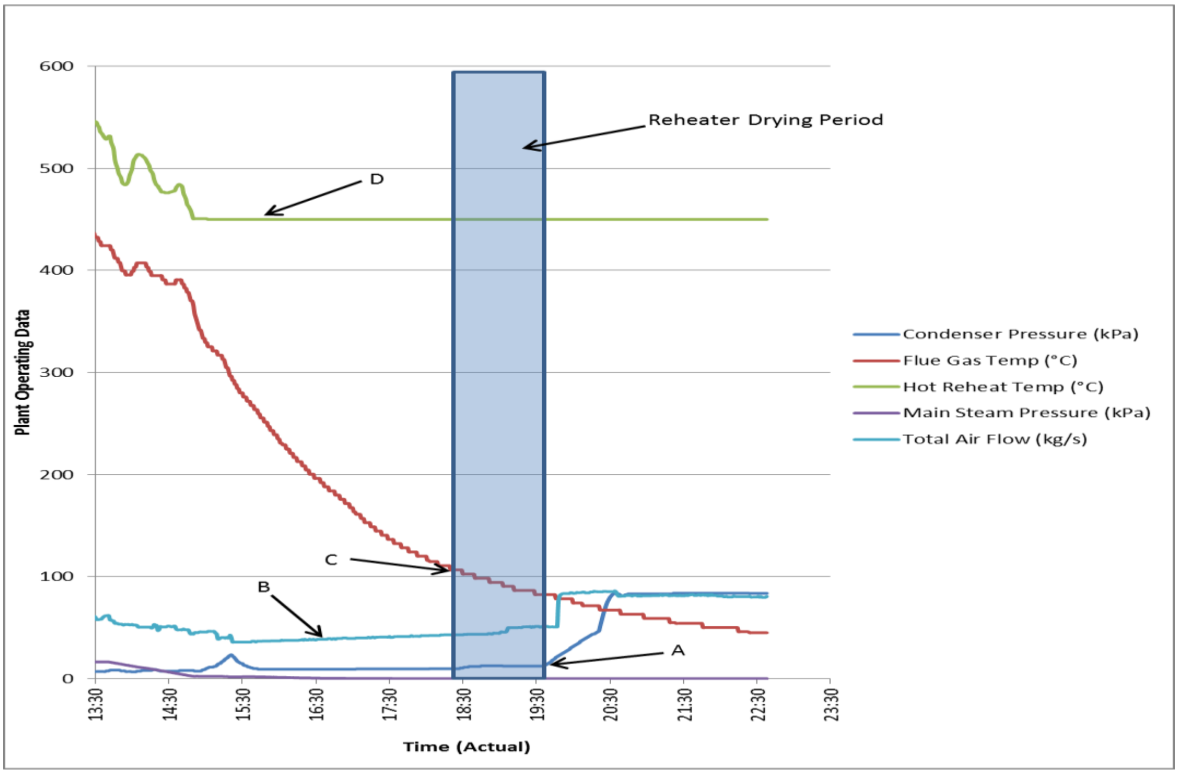

Figure 4-3: Vacuum drying plant data at Power Station B

The blue shaded area in Figure 4-3 indicates the drying period with air flowing through the reheater commencing at 18:25 when the air inlet valves were opened. Drying was completed at 19:34 which is when the vacuum in the condenser was broken, indicated by A. This is 1 hour of ambient air flow through the reheaters. The line marked B in Figure 4-3 is the total air flow which refers to the air flowing from the SA fan to force cool the boiler. The flow is approximately 50kg/s. This is not according to the procedure which requires the boiler to be boxed (no air flow) until reheater drying is completed. The operator logs (Table 4-2) show that full boiler forced cooling starts at 19:30 which increases the air flow to approximately 80 kg/s. This step change can be seen on the line marked B. The 50kg/s flow is regarded by the operators as a period of low air flow. During the low flow period the flue gas temperature continues to decrease. By the time air was allowed into the reheater the flue gas temperature was just above 100°C and soon dropped below. This is indicated by C which represents the flue gas temperature leaving the reheaters. The remainder of the drying occurred with tube temperatures below 100°C. This means that whatever moisture is within the tubes will condense and humidity measurements will be affected and not give a true reflection of the moisture content within the reheaters. The hot reheat steam temperature (D) levels off at 450°C which was an instrument error as advised by operating staff. This should steadily decrease. Testing commenced at the end of reheater drying. Results are shown in Figure 4-4.

Table 4-2: Operator logs during vacuum drying at Power Station B (test 1)

No.	Time	Comment
1	15:19	Boiler Purge Completed
2	18:25	Air Inlet Valves opened for reheater drying
3	19:37	Force cooling in progress on boiler (80%)

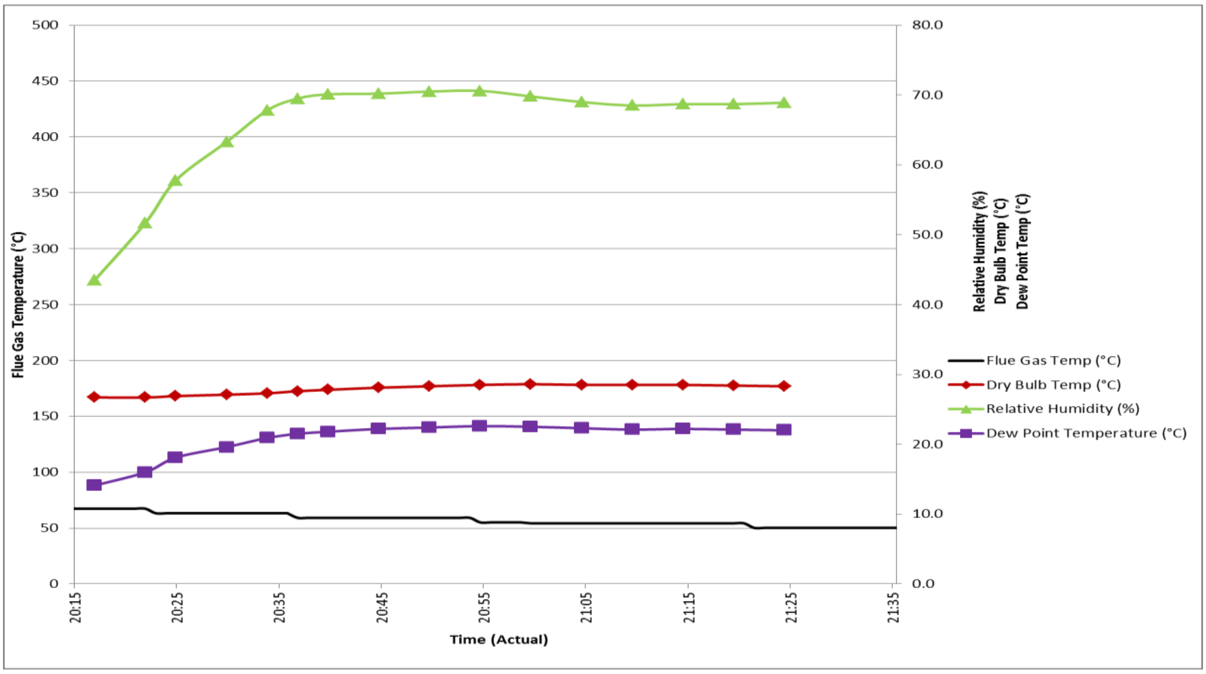

Figure 4-4: Vacuum drying test 1 results at Power Station B

Testing only commenced after reheater drying was complete and the vacuum from the condenser switch off and the reheaters were at ambient pressure. It can be seen that relative humidity increased initially. This is due to the time taken to fill the humidity box with fluid from the reheater. The box was larger than the one used during the forced drying testing as a smaller box was reverted to during the forced drying test to speed up the time for measurements to stabilise. Thereafter it stabilised and the final measurements were 68.9 % at 28.3°C with a dew point temperature of 22.2°C.

This shut down differed from the procedure. The procedure required 2 hours of drying with a boxed boiler. This shut down had low air flow with only 1 hour of air flowing through the reheaters. This is due to a temporary operating procedure in place allowing for the first hour maintaining a vacuum in the reheaters and the second hour opening up the air inlet valves to allow air to pass. In order to test the effectiveness of the procedure a second test was conducted at the next shut down with a boxed boiler and with a full 2 hours of air flow through the reheater.

Plant data for the second test shut down is shown in Figure 4-5.

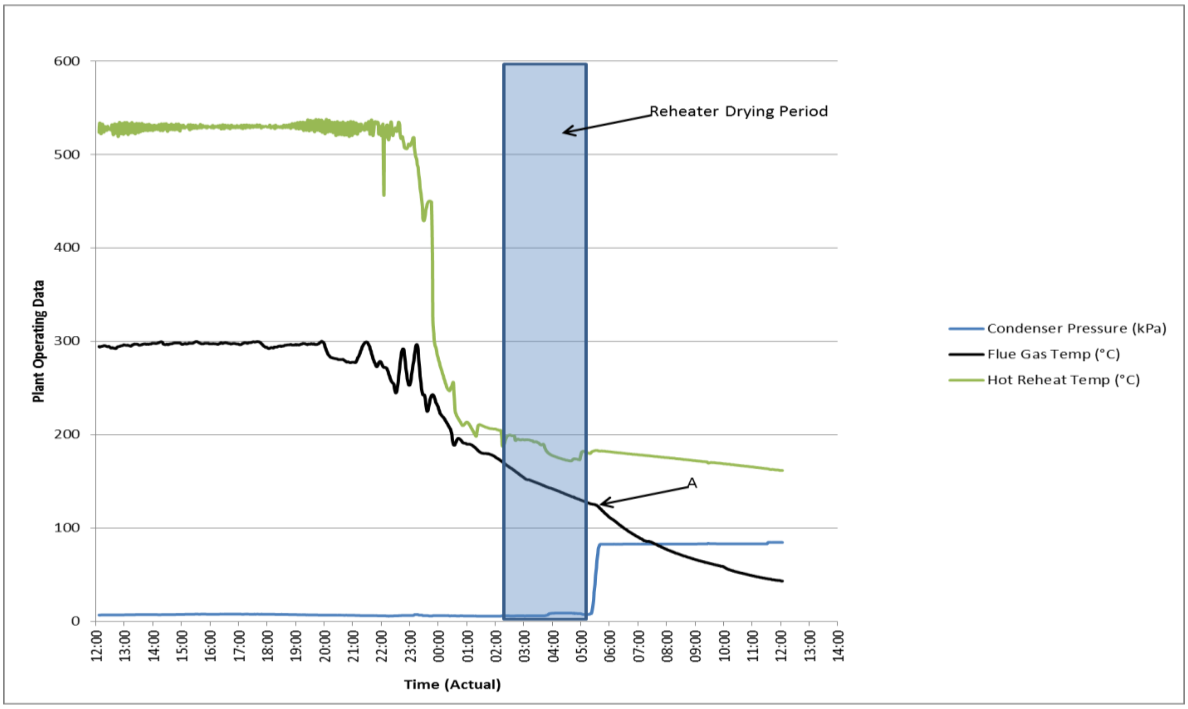

Figure 4-5: Plant data for Power Station B vacuum drying test 2

In Figure 4-5 the blue shaded area indicates the 3 hours of drying with air flow through the reheaters. The additional hour was due to an problem shutting down the ejector system maintaining the vacuum in the condenser. Drying commenced at 02:10 AM and ended at 05:15 AM. The boiler was boxed static air in the boiler. This is not shown in the figure but from operating logs (Table 4-3) the air flow was only increased once drying was completed. This is evident from the flue gas temperature being above 100°C (marked A) for the full duration of the drying. This means that no condensation took place and drying was carried out while the fluid in the reheaters was in gaseous state. The blue line (condenser pressure) indicates when vacuum drying stopped, i.e. when the vacuum in the condenser was broken and allowed to increase to atmospheric pressure.

Relative humidity measurements were taken at the end of drying, once pressure in the reheater was atmospheric, and found to be 100% at 42.6°C with a dew point of 42.6°C as can be seen in Figure 4-6.

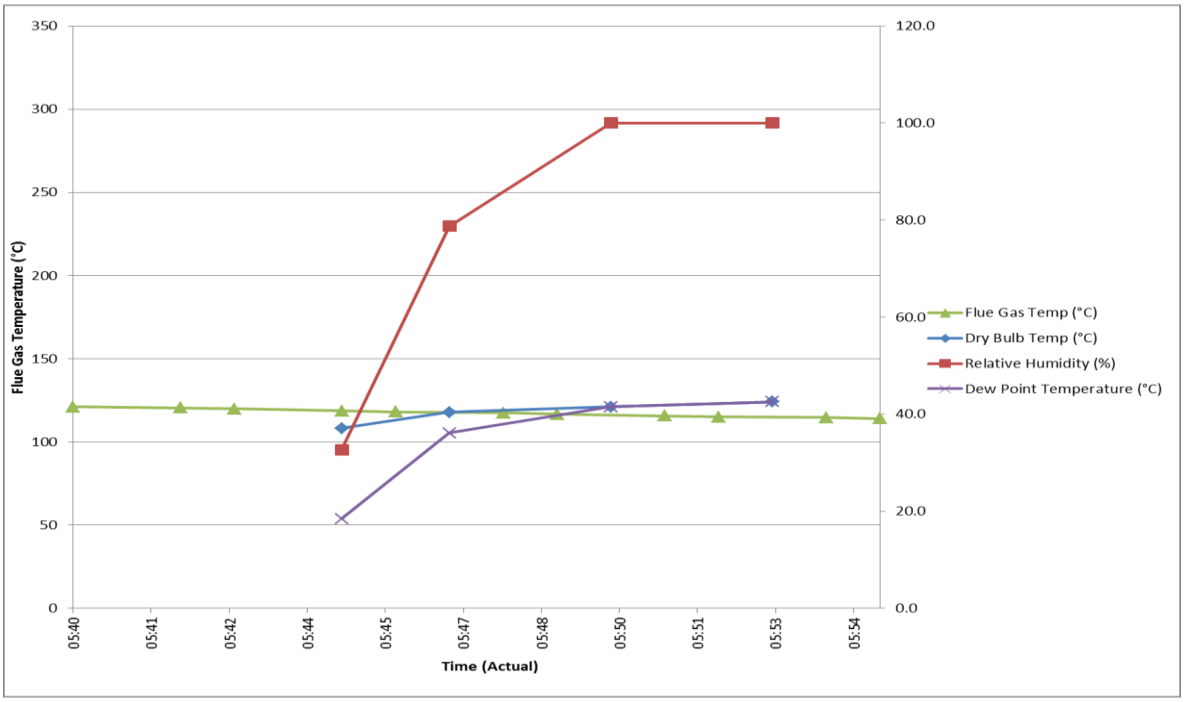

Figure 4-6 : Vacuum drying test 2 results at Power Station B

Once 100% humidity was measured the fluid coming into the humidity box started to condense and the test was ended to protect the equipment. The relative humidity is higher in the second test because all the fluid in the reheater is still in steam form. In the previous test, boiler forced cooling commenced before reheater drying, cooling the boiler to a point where condensation will occur resulting in lower humidity measurements.

Table 4-3: Operator logs for vacuum drying test 2 at Power Station B

No.	**Time**	**Comment**
1	01:30	Boiler Purge Completed
2	02:10	Start Reheater Evacuation as per procedure
3	03:44	Air admission valves open
4	05:15	Reheater Drying Completed
5	05:45	Vacuum Broken on Main Condenser
6	05:50	Air Flow increased to 50%

4.1.3 Boil Drying Test Results at Power Station C

The plant data for the shutdown, collected from the station logs, are presented below in Figure 4-7.

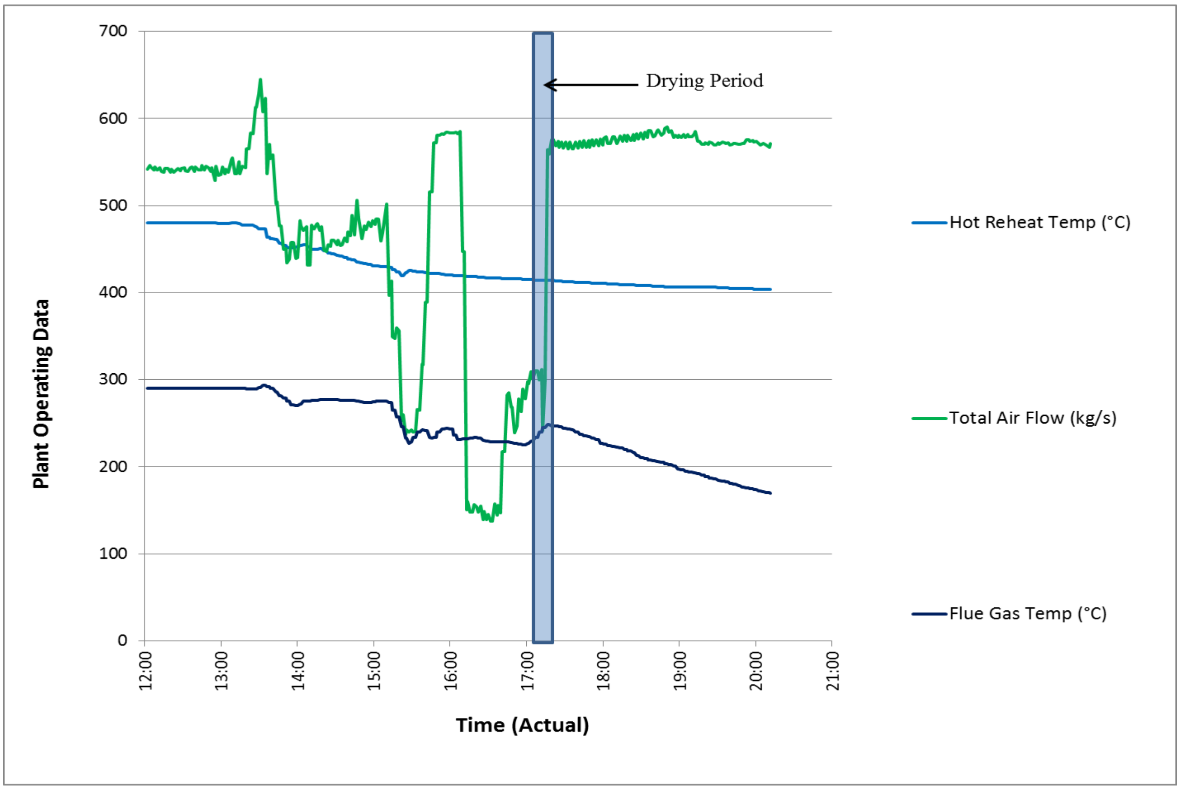

Figure 4-7: Plant data from boil drying test at Power Station C

The blue shaded area indicates 10 minutes of drying. This procedure burns fuel oil at high fire for 10 minutes while opening up the vents and drains on the reheater in order to boil out any water collecting in the tubes. The flue gas temperature before the fuel oil was burnt was already at 226°C, therefore, the fluid in the reheater is already in steam form. Increasing the temperature will cause the steam to expand causing it to escape from the vents and drains. After boiling is completed, the vents and drains are closed and forced cooling of the turbine takes place. The compressed air cooling the turbine is allowed to enter the reheater but with vents and drains closed the reheater is pressurised. Measurements were taken at the pressure transducer on the hot reheat line. When the test point was opened, wet steam emitted and continued to come out for a few hours. The temperature of the wet steam was 90°C. The barometric pressure at the station was 90.7kPa thus steam will condense at a temperature of 96.9°C (steam tables) [53] at this power station. This wet steam started condensing on the humidity meter and thus the test was stopped to protect the instrument.

Measurements were taken 12 hours later to determine the conditions inside the reheater after it has cooled own. Figure 4-8 below depicts the results.

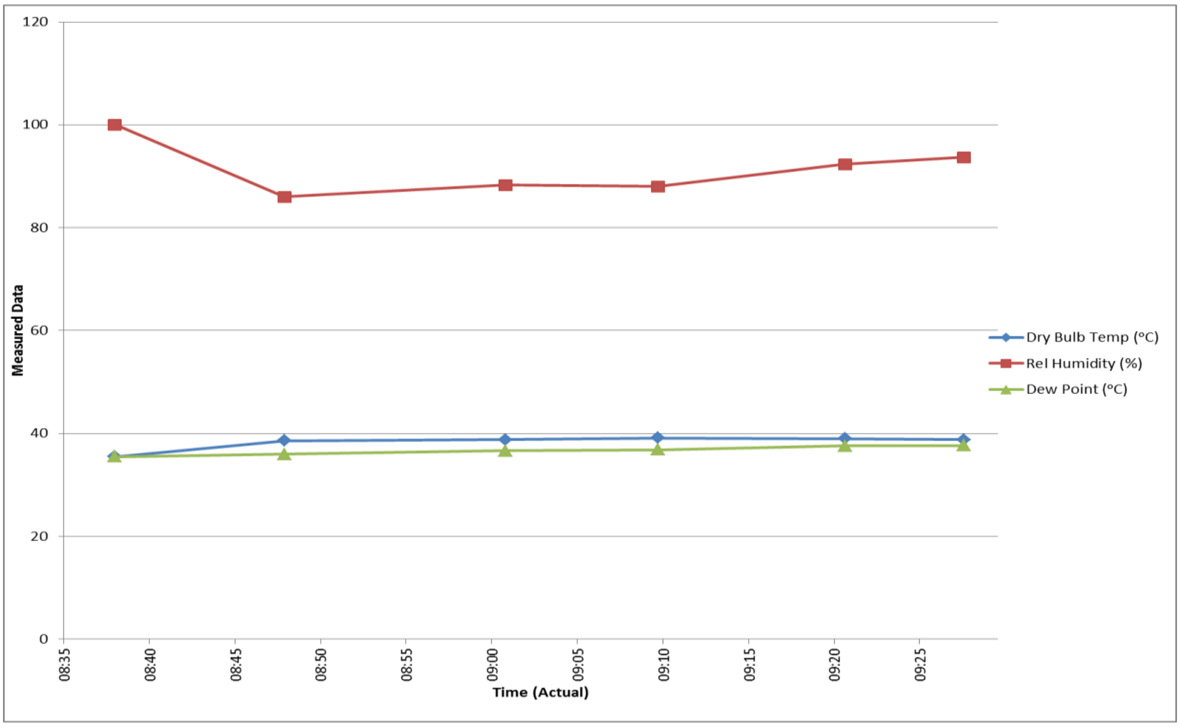

Figure 4-8: Measured data from Power Station C 12 hours after drying

As the boiler cooled down the steam in the reheaters condensed which results in lower relative humidity values measured. However, even with this lower measured values the boiler was left in a condition with high relative humidity of 93.7% at 38.8°C with a dew point of 37.6 °C.

4.2 Uncertainty Analysis

An uncertainty analysis was carried out to determine the uncertainty in results obtained from measurement. The total uncertainty is quantified using partial differentiation of the derived parameter (dew point). Table 4-4 gives the uncertainty for the three relative humidity at the three temperatures used in calibration of the equipment. Details can be found in Appendix B.

Table 4-4: Uncertainty Analysis

Temperature (°C) (±1°C)	Relative Humidity (%)(±2%)	Uncertainty U(Td) (±°C)
10	11	0.6
50	11	2.4
90	11	4.5
10	53	0.4
50	53	1.1
90	53	2.0
10	75	0.3
50	75	1.1
90	75	1.7

This shows the uncertainty increases at higher temperatures and lower relative humidity. For a maximum allowable uncertainty of 5% in dew point temperature the maximum allowable uncertainty in temperature (uT) is 0.99°C and relative humidity (uRH) is 13.27%.

4.3 Discussion

The three methods of drying at seven power stations were tested for their effectiveness in drying the reheaters. Table 4-5 shows the comparison of the results from the three method of drying as soon as drying was completed. The basis of comparing the three methods is the dew point temperature as dew point temperature is a function of the moisture content of the fluid whereas relative humidity is a function of temperature and moisture content. This can be seen from the psychrometric chart in Appendix D.

Table 4-5: Comparison of results

Drying Method	Power Station	Measured				Ambient
		RH (%)	T (°C)	Td (°C)	U(Td) (±°C)	T (°C) (±0.2°C)
Forced	A	13.7	31.5	0.9	2.7	25.8
	D	40.4	27.5	13.1	1.5	21.7
	E	49.9	23.9	13	1.2	18.3
Vacuum	B	100	42.6	42.6	1.5	22.6
	F	100	14.8	14.8	0.7	13.7
	G	100	36.2	36.2	1.3	36.2
Boil	C	100 (Steam)	90	96.9		27.2

Figure 4-9 below further illustrates the comparison of the dew point temperature after drying to the ambient temperature when at the specific time.

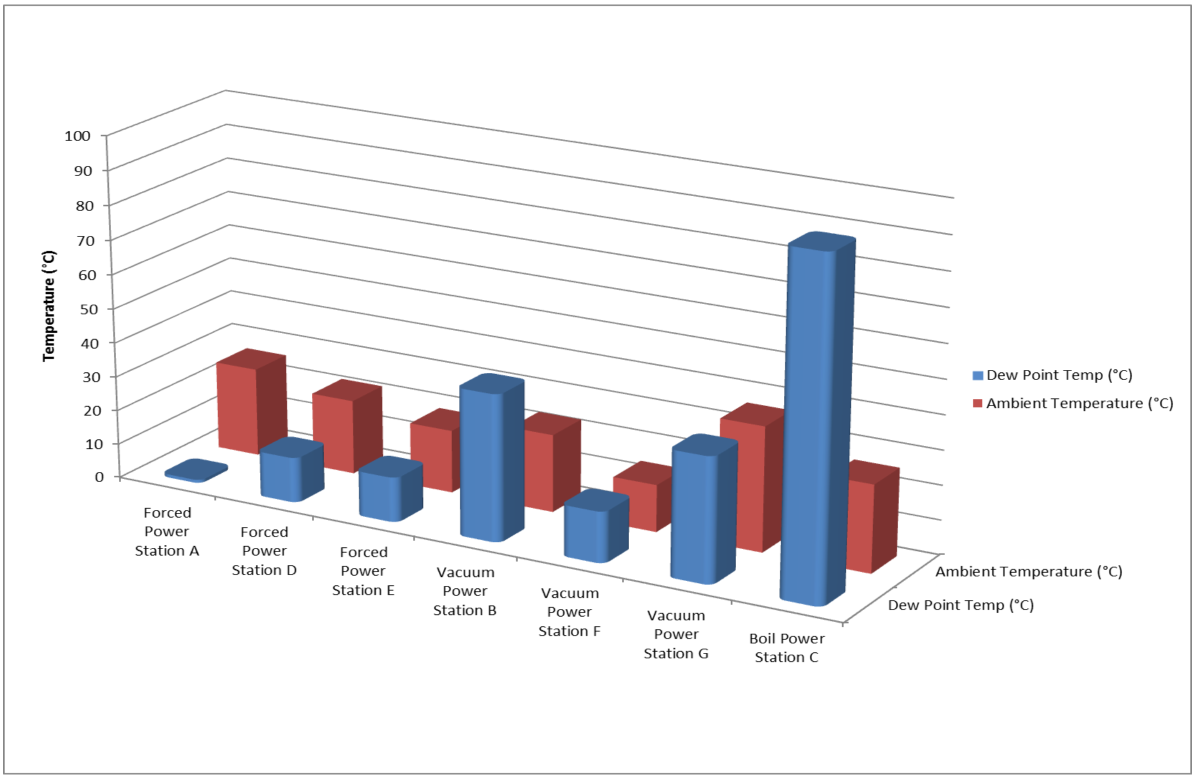

Figure 4-9: Dew Point Temperature Comparison

Figure 4-9 shows that all the forced drying stations leave the reheaters with a dew point temperature lower than ambient temperature, which will ensure no condensation and thus no pitting. However, all the vacuum drying power stations and the boil drying power station leave the reheater with dew point temperatures equal or higher than ambient temperatures. Condensation will occur and has been witnessed during testing.

4.3.1 Forced Drying

Power Station A had a dry fluid with a relative humidity of 13.7% at 31.5°C and a dew point of 0.9°C. The ambient temperature was measured to be 25.8°C with a dew point calculated to 17.3°C. Taking into account the maximum uncertainty, the dew point temperature of 3.6°C is still well below the ambient temperature of 25.6°C.

This power station makes use of a large compressor delivering approximately 100kg/min at 800kPa (g) air into the reheater. The compressor removes some of the moisture present in the air and discharges it. The air is then heated in the pipework of the boiler allowing the air used for drying to have a higher moisture holding capacity, which explains the low dew point measured as compared to ambient air. The forcing of air out of the reheater and replacing with air results in the low dew point and relative humidity measurements seen. The spikes in the relative humidity and dew point during the forced drying can only be due to moisture entering the system. The moisture entering is unknown at this point, but could be due to a spray water valve passing or some water carried over from the compressor. However, this will not result in condensation collecting the tubes as the tubes are still above the boiling point as indicated by the high flue gas temperature throughout the drying period. This forced drying station has not had any signs of pitting since force drying was implemented in 2000 indicating its effectiveness. Routine samples every outage (3 years) were checked for any signs of pitting and no pitting has been identified since forced drying. The Eskom system for analysing tubes involves visual examination, chemical analysis of corrosion product, wall thickness measurements and metallographic examination that was performed on all tube samples sent to the metallurgical department as per the EPRI guidelines [9].

Power Station D had a dry fluid with a relative humidity of 40.4% at 27.5°C and a dew point of 13.1°C. The ambient temperature was measured be 21.7°C with a dew point calculated to -0.4°C. Taking into account the maximum uncertainty, the dew point temperature of 14.6°C is still well below the ambient temperature of 21.5°C.

This power station makes use of a compressor delivering air at an outlet pressure of 480kPa air into the reheater. At maximum pressure, the inlet air at the compressor is $20m^3$/min. The compressor delivers this air through the turbine, thus cooling the turbine as well. The lower flow rate from this portable compressor ,compared to the compressors at Power Stations A and E, adds to the required drying time.

Power Station E had a dry fluid with a relative humidity of 13.7% at 23.9°C and a dew point of 13.0°C. The ambient temperature was measured to be 18.3°C with a dew point calculated to 13.9°C. Taking into account the maximum uncertainty, the dew point temperature of 14.2°C is still well below the ambient temperature of 18.1°C.The reheater dew point being only slightly lower than ambient dew point.

This power station makes use of a compressor delivering air with a maximum outlet pressure of 250kPa (gauge) air into the reheater and an air inlet flow rate of $120m^3$/min. During reheater drying the compressor deliverer pressure is 180kPa (g). This station delivers the air through the HP turbine which also adds to the required reheater drying time as compared to Power Station A but due to the higher air flow, the drying time is less compared to that of Power Station D.

4.3.2 Vacuum Drying

Power Station B's first test showed relative humidity measurements of 68.9% at 28.3°C with a dew point temperature of 22.1°C. This is lower than the second test which had 100% humidity, however, the first test measurements are not a true representation of the fluid properties in the reheater. During this time even though the air flow was low, significant cooling of the boiler tubes took place. By the time reheater drying started the flue gas temperature was slightly over 100°C and shortly after reheater drying started the flue gas temperature dropped below 100°C which will result in condensation taking place. Besides, the literature review elaborated that boiler draining should take place when the boiler is hot to avoid the condensation of fluid inside which will be almost impossible to drain without cutting tubes.

During the second test flue gas temperatures remained well over 100°C ensuring that no condensation took place and the fluid tested was a true representation of what was inside the reheaters. The vacuum on the condensers and only one open air inlet valve does not allow a large volume of air to replace the steam. Even though air does enter the system it was not sufficient dry the reheaters and thus produced the result of 100% humidity and dew point of 42.6 °C. This means that as soon as the boiler temperature cools to 42.6°C the fluid in the reheater will condense. The ambient conditions measured was a dry bulb temperature of 22.6°C with a dew point of 14.4°C. As the ambient dew point was lower than the fluid in the reheater dew point, condensation will take place and this was witnessed during the test. Condensate formed inside the humidity box as the fluid entered. When moisture condenses in the tubes, pools form in the low lying areas of the boiler tubes which are rich in oxygen thus the conditions for pitting are present. As the condensate forms on the boiler tubes the deposited salts dissolve and collect in the pool in the low lying areas, thus high concentration of salts in the pool aggravate pit formation.

Power Station F and G with the drum 2-pass type boiler had the same overall result as Power Station B with the once through tower type boiler. All vacuum stations left the reheaters with high dew point temperatures.

If vacuum drying was effective it would only replace the steam with the ambient air quality. If this drying was done on a rainy day high moisture content air will enter the boiler tubes.

Having a vacuum on the reheater also allows for dust, flue gas and other foreign particles to enter into the reheater which may lead to other problems. As part of the outage scope, routine inspections are made to boiler tubes at corrosion prone areas. X-rays as well as tube samples are taken are sent for metallurgical inspection to identify corrosion related problems. Samples are sent if a failure occurs or when an outage takes place and the opportunity to cut tubes arises. Power Station B and F has reported pitting as a problem in the past as it was noticed on sampled tubes and failures have occurred which resulted from pitting corrosion. This is evident from reports issued by Eskom's Research, Testing and Development Department. Power Station G has not had any failures due to pitting corrosion, however tube samples were not taken in the past to confirm the presence of pitting or not. The major contributors to tube failures were fly ash erosion and short term overheating. However, there is no certainty that some failures did not initiate from pitting and the failure could have been attributed to another mechanism.

4.3.3 Boil Drying

The boil drying procedure at Power Station C does not replace any steam with air. No boiling of liquid actually takes place as the fluid in the reheaters are already above 200°C at atmospheric pressure. This is evident from the high flue gas temperatures. The boiling only expands the already present steam allowing some to escape out of the vents and drained. As soon as this fluid cools during the force cooling of the boiler it will condense. Wet steam exited the test point with 100% humidity measured at 90°C. The annual average dew point calculated for this region is 11°C. The average annual temperature in this region is 27.2°C [55]. Before the test Power Station C's engineering department reported that no failures had occurred due to pitting corrosion and hence pitting corrosion was never inspected for. Ten samples were taken from the reheater tubes and sent for metallurgical analysis to Eskom's Research Testing & Development department which reported all ten samples had pitting corrosion confirming implications of the test that boil drying is ineffective.

4.3.4 Flow Comparison between Vacuum and Forced Drying

Power Stations B and E have exactly the same design with regards to the boiler. Power Station B makes use of vacuum drying while Power Station E makes use of forced drying.

Under normal operating shut down, the system temperatures and pressures are the same at the time reheater drying commences. To compare the two different drying methods used, the flow rate for the system is calculated. The assumption and detail calculations used can be seen in Appendix E. An iterative process is followed by guessing a velocity value at the inlet and computing the pressure drops along the system. Thereafter adjusting the inlet velocity value until the sum of the pressure drop equates the total pressure drop. This was done for each method of drying. The results are tabulated below in Table 4-6.

Table 4-6: Flow rates calculated at average air density

	Vacuum Drying (Power Station B)	**Forced Drying (Power Station E)**
Inlet Velocity (m/s)	17.31	15.84
Volumetric Flow Rate (m^3/min)	18.35	16.79
Mass Flow Rate (kg/min)	10.24	33.94

As mentioned, both power stations have the exact same design with a total reheater volume including the headers of $170m^3$. Both stations have a drying duration of 2 hours. Based on the above flow calculations the Power Station B has one volume exchange in 9.26 minutes and 13 volume exchanges in the 2 hour drying period. Power Station E has one volume exchange in 10.13 minutes and 11.85 volume exchanges in the 2 hour drying period. However, using a compressor to force air into the system has a much higher mass flow rate compared to that of vacuum drying. Under forced conditions the air density increases thus more steam is replaced by air making forced drying more effective.

During normal shut down conditions, the flow rates will be less, as the system restrictions are higher. The effect of mixing will also be present as the air will mix with the steam. The pipes and tubes are filled with steam offering resistance as well as other piping restrictions not taken into account, such as bends. The density of the air will change as it is heated up by the hot pipework which will also reduce the flow rate, however, the calculated results prove what has been observed during dew point testing. The air entering during normal conditions has some moisture present. Some of this moisture will be removed during the compression. The heating of the air in the pipework will also increase the moisture carrying capability of the air.

Forced drying is a more effective means of drying the reheater to prevent pitting as, the objective of replacing steam with air is obtained much faster as compared to vacuum drying. Having higher ΔP values with larger compressor will increase the density and thus mass flow as was observed with Power Station A. Drying will take place in a shorter time.

4.3.5 Conclusion to Results and Discussion

The results have shown that forced drying is the most effective method of drying as it has replaced steam with dry air and left the reheater in a condition where no condensation which will lead to pitting corrosion taking place. This was the case for both once through tower boilers (Power Station E) as well as drum 2-pass boilers (Power Stations A and D). Even though the boiler types and design were different, results were consistent with the method of drying used at the power stations. As mentioned in the literature review, making use of compressed air to dry the boiler tubes is the preferred method to facilitate draining and drying of steam tubes while the metal is still warm [34]. Vacuum and boil drying are ineffective methods of drying as the reheaters were left in a state with 100% relative humidity which when cooled will condense and lead to pitting corrosion. This was further proved by calculations. The higher density air as a result of pressuring from the compressor results in a higher density and thus more than 3 times higher mass flow through the reheaters as compared to drawing a vacuum. The larger ΔP driver for flow from the forced drying compared to vacuum drying results in steam evacuated quicker and thus better drying is achieved.

Boxing of the boiler until reheater drying is completed is an essential part of boiler shut down to ensure the drying is effective.

CHAPTER 5: CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

Based upon the literature and results of this research the following conclusions have been made:

- As discussed in the literature review, pitting corrosion in boiler tubes can only occur when oxygen rich stagnant water is present during the boiler outage time. This oxygen rich stagnant water occurs because of poor shut down practices. Effectively drying the tubes during the shutdown will prevent the formation of condensate thus preventing pitting from occurring.
- The plant data collected during the shutdown has shown that forced cooling of the boiler before reheater drying allows the boiler tubes to be exposed to cold air. When the metal temperature drops below the boiling point of the steam inside the tubes, condensation will take place. Once condensation has formed, drying will be ineffective. The boiler needs to be drained and dried while still hot. This is achieved by boxing up the boiler, which ensures that the boiler internals remain hot until reheater drying is complete.
- Drying requires the replacement of steam with dry air. Forced drying with a compressor delivering a large air mass flow rate is an effective method of drying. Steam is effectively replaced with dry air thus ensuring no condensation will take place once the tubes are cooled as discussed in section 4.2.1. This was not achieved by vacuum drying as discussed in the results section 4.2.2. The air flow into the reheater is not sufficient to replace the steam. Vacuum drying also allows for harmful substances like dust and flue gas to enter into the boiler tubes which may lead to further problems.
- Boil drying is not an effective method of drying, as it does not replace any steam with air. The steam inside the tubes is only allowed to expand with some escaping out the vents as discussed in 4.2.3.

- The literature guidelines have shown that to prevent offline corrosion, low-humidity air needs to be circulated inside the boiler tubes during the storage period. This will keep the relative humidity below 60% lowering the rate of corrosion of the steel.
- It was observed that procedures are not always followed by the operators. Some procedures specify that boiler forced cooling should be delayed until reheater drying has completed but this is ignored with the intension to reduce the shutdown time. Some shutdowns, certain valves which are specified to be shut during drying are left open as a result of poor discipline.
- Other maintenance issues also affect poor shut down practice such as spray water valve passing, compressor trips and unavailability with no backup system in place.

5.2 Recommendations

It is recommended that forced drying of the boiler tubes be implemented at all power stations. The power stations can make use of their turbine forced cooling compressor to dry the reheaters. A common line to all units should be installed and the process automated. The results from the forced drying Power Station A shows that using the 800 kPa compressor the boiler tubes were dried to atmospheric conditions within an hour. It is recommended that all stations should dry the reheater for a minimum of 2 hours depending on the size of the available compressor. As soon as the reheat pressure is 0 reheater drying should commence. Boxing of the boiler after boiler purge is completed is essential for ensuring the fluid inside the tubes remains in gaseous form and can easily be forced out using the compressed air. If possible the compressor should be fitted with a dryer to ensure dry air is used to dry the reheater even during rainy and wet conditions. Some stations do not perform drying during short outages (less than 3 days). Short outages sometimes tend to be longer as other maintenance requirements emerge when the unit is off, therefore, and so it is recommended that all shut downs requiring the draining of the boiler should have reheater drying.

As the literature has elaborated, boiler layup and storage to protect the boiler from offline corrosion is important. The circulation of dehumidified air is the easiest solution in the South African environment where tubes need to be worked on and the dry air can be switched off and restarted when work is complete. If this cannot be achieved, once forced drying has been completed and the steam replaced by air, control air from the power station which has desiccant dryers can be supplied to the reheater to further dry the air inside the reheaters.

Boiler shut down procedures can only be effective if they are followed. The operator logs should be checked at random to determine if operators are following the procedure. An online dew point instrument can be installed to monitor the dew point during the shutdown. This will help in tracking the effectiveness of all shut downs.

Spray water valves should be maintained such that they are not passing to ensure no water enters the system during drying. Compressors should be well maintained and checked regularly. When maintenance is required, backup compressors should be available in the event of a shutdown requiring drying.

Further test work can be conducted at all power stations to determine if their turbine forced cooling compressor is sufficient to perform the drying. The equipment used during this test was effective for dew point and relative humidity testing. Modifications to the plant to install dedicated dew point temperature test point which are close to the reheater tubes which have no loops to prevent condensate build up with easy connection will assist in future tests.

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APPENDIX A: VACUUM PUMP PERFORMANCE CURVE

Figure A-1 below is the pump performance curve for the Vacutronics DP-200H vacuum pump supplied by Vac-Cent Services (Pty) Ltd

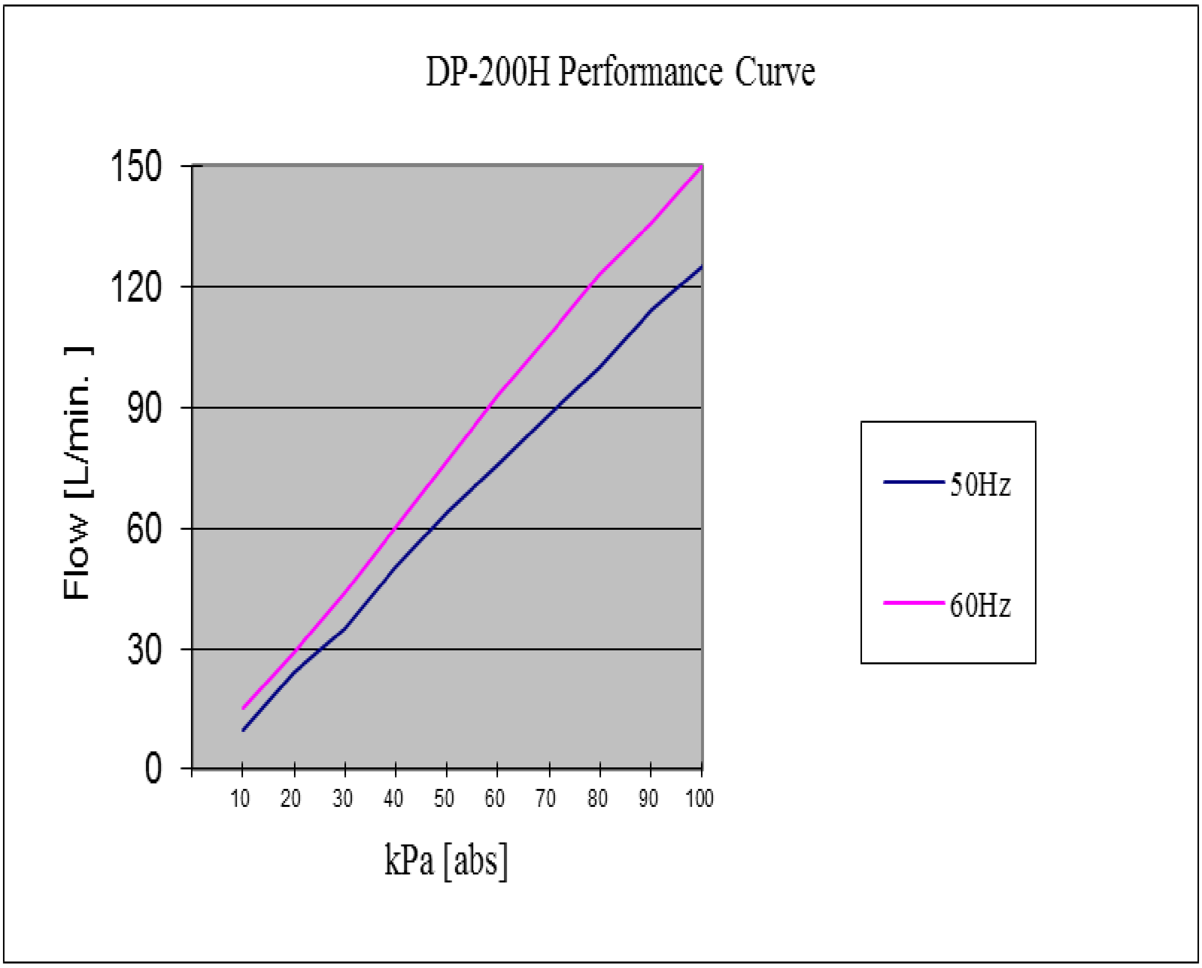

Figure A-1: Vacuum pump performance curve

APPENDIX B: INSTRUMENT CALIBRATION AND UNCERTAINTY CALCULATIONS

Calibration

The Testo 635 instrument was calibrated according to SANAS (South African National Accreditation) standards. The instrument was calibrated at three temperatures namely 10°C, 50°C and 90°C, and three relative humidities namely 11%,53% and 75%. Calibration curves were plotted using the measured data and the actual data. This can be seen in Figure A1 and A2 respectively.

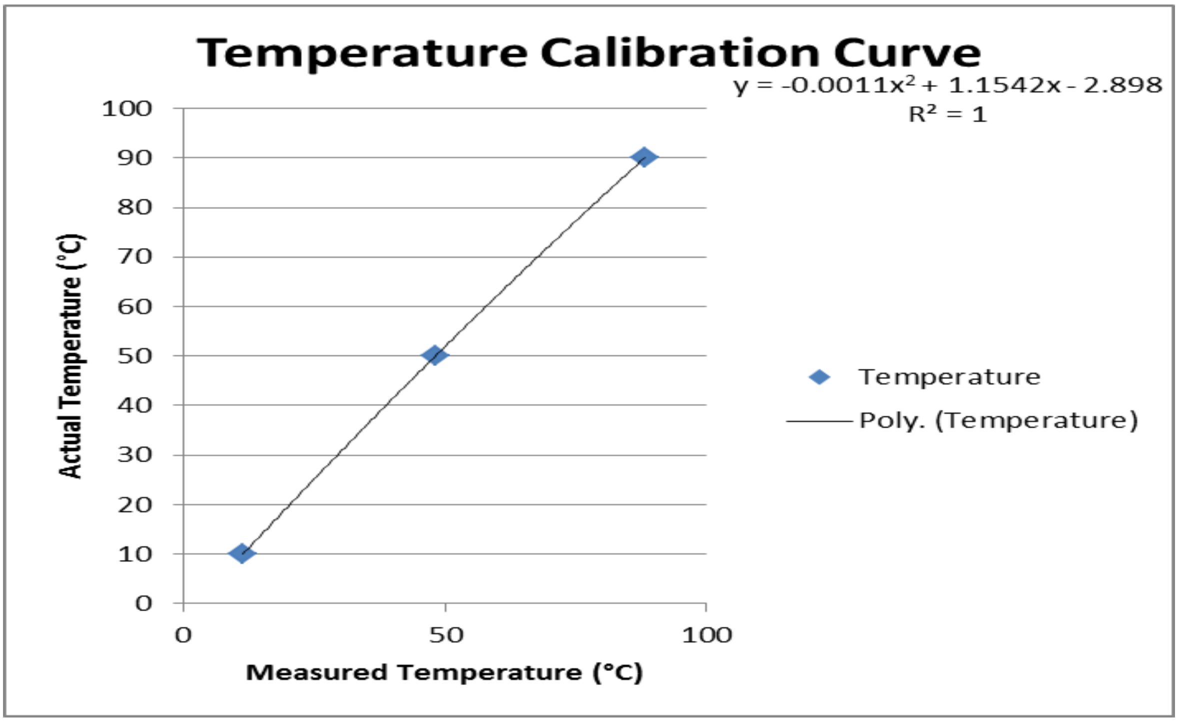

Figure B-1: Temperature Calibration Curve

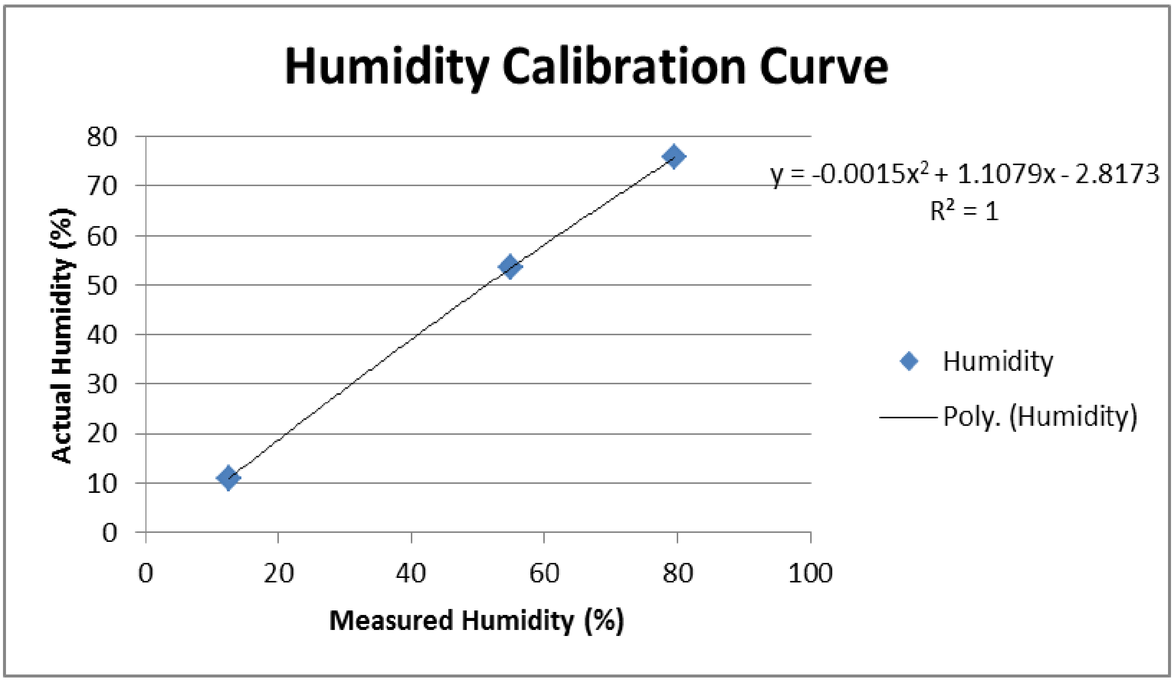

Figure B-2: Relative Humidity Calibration Curve

Figure B1 and Figure B2 were used to correct the measured data using the following equations (B1 and B2) which resulted from fitting a curve to the calibration data.

Equation 4: Temperature correction

$$y = -0.0011 + 1.1542x - 2.898$$

Equation 5: Relative humidity correction

$$y = -0.0015x^2 + 1.1079x - 2.8173$$

Uncertainty Calculations

Total uncertainty is determined by the following equation [56].

$$U(X) = \sqrt{\left(\frac{\partial X}{\partial Y_1}\right)^2 (uY_1)^2 + \left(\frac{\partial X}{\partial Y_2}\right)^2 (uY_2)^2 + \left(\frac{\partial X}{\partial Y_3}\right)^2 (uY_3)^2 + \cdots}$$

Where X is the derived parameter which is a function of Y_1, Y_2 etc. which is the uncertainties in measurement from the instrument, test conditions etc. uY_i is the standard uncertainty with respect to Y_1, Y_2 etc. and is calculated using a rectangular distribution [54] as follows:

$$uY_1 = \frac{a_{Y_1}}{\sqrt{3}}$$

Dew point temperature (Td) is a function of relative humidity (RH) and dry bulb temperature (T) and is expressed by the following equation.

$$Td = T\left[1 - \frac{Tln\left(\frac{RH}{100}\right)}{\frac{H_{vap}}{R_w}}\right]^{-1}$$

Where:

R_w is the gas constant for water vapour (461.5JK^{-1}kg^{-1})

H_{vap} is the enthalpy of vaporization

(H_{vap} = 2.501 x 10^6 J.K^{-1}at T = 273.15 K and H_{vap} = 2.257 x 10^6 J.K^{-1} at T = 373.15 K)

Thus the uncertainty in dew point temperatures is expressed by **Error! Reference source not found.**.

Equation 6: Uncertainty in calculated dew point temperature (Td)

$$U(Td) = \sqrt{\left(\frac{\partial Td}{\partial T}\right)^2 (uT)^2 + \left(\frac{\partial Td}{\partial RH}\right)^2 (uRH)^2}$$

The partials derivatives are as follows:

$$\frac{\partial Td}{\partial T} = \frac{1}{\left(1 - \frac{Tln\left(\frac{RH}{100}\right)}{H_{vap}/Rw}\right)}$$

$$\frac{\partial Td}{\partial RH} = \frac{\frac{100T^2}{RH.\,{}^{H_{vap}}/Rw}}{\left(1 - \frac{Tln\left(\frac{RH}{100}\right)}{H_{vap}/Rw}\right)}$$

As per the Testo 635 manufacturer specification:

Uncertainty in temperature measurements aT = ±0.2°C for T = -10° - 50°C and ±0.5°C for above 50°C

Uncertainty for relative humidity aRH = ±2% (+2 to 98% RH)

The uncertainty can also be expressed by the following non-dimensional equation.

$$\left(\frac{U(Td)}{Td}\right)^2 = \left(\frac{T.\partial Td}{Td.\partial T}\right)^2 \left(\frac{uT}{T}\right)^2 + \left(\frac{RH.\partial Td}{Td.\partial RH}\right)^2 \left(\frac{uRH}{RH}\right)^2$$

Where:

$$\frac{T.\partial Td}{Td.\partial T} = \frac{1 - \frac{Tln\frac{RH}{100}}{{H_{vap}}/{Rw}}}{T} \frac{T}{1 - \frac{Tln\frac{RH}{100}}{{H_{vap}}/{Rw}}} = 1$$

$$\frac{RH.\partial Td}{Td.\partial RH} = \frac{100T(1 - \frac{Tln\frac{RH}{100}}{{H_{vap}}/{Rw}})}{{H_{vap}}/{Rw}}$$

The maximum allowable uncertainty for each of the measurements, viz. temperature and relative humidity can be determined for a known total uncertainty in dew point. The maximum allowable uncertainty will be at the highest relative humidity (100%) and lowest temperature that will be measured. The lowest possible temperature will be ambient temperature and at most power stations the boiler house temperature is approximately 20°C. Thus at these conditions with a total uncertainty in dew point of 5% the maximum allowable uncertainty in temperature (uT) is 0.99°C and relative humidity (uRH) is 13.27%. Using the instruments uncertainty in measurement of uRH = 2% and uT = 0.2°C the uncertainty in dew point is 7°C.

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Calibration Laboratory
146 308 1546 1446

CERTIFICATE OF CALIBRATION

South African National Accreditation System
Accredited Laboratory Number 308 / 146 / 1546 / 1446

CERTIFICATE NUMBER: 1546-11501

Calibration of a	:	ThermoHygrometer
Manufacturer	:	Testo
Model No	:	635
Serial No	:	02114289/106
Sensor's Serial No	:	26362161/105
Calibrated for	:	Eskom Holdings
Address	:	Eskom Holdings SOC Ltd Lower Germiston Road Cleveland
Issue Date	:	23 January 2014
Calibration Date	:	22 January 2014
Technical Signatory	:	J.L. Steinberg ....
Calibrated by	:	J. Ysel(Jnr)
Checked by	:	M. Gomes

The South African National Accreditation System (SANAS) is a member of the International Laboratory Accreditation Co-Operation (ILAC) for the Mutual Recognition Agreement (MRA). The MRA allows for the mutual recognition of technical test and calibration data by the member accreditation bodies worldwide. For more information on the MRA please refer to www.ilac.org

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1. LABORATORY STANDARDS AND EQUIPMENT USED FOR MEASUREMENTS

The equipment used for measurements are listed below

Standards and Equipment	Serial Number	Certificate Number
STD Rotronic HP 22 Hygrometer	60751285	1546-8919
STD Rotronic Hygro clip sensor	60775925	
Pt 100 and Thermometer	2015282/001/001/005/02	308-260313577
SC 33 Novisina 33%rh STD Salt Cell	1009093	HM\ES-3095
SC 53 Novisina 53%rh STD Salt Cell	710104	HM\ES-3096
SC 75 Novisina 75%rh STD Salt Cell	1009017	HM\ES-3097
Rosemount Resistance Temperature Device	4205	TH/RT 6350
Tinsley &Co 100Ω Resistor	222.013	79865
ASL F700 Bridge	12264340	-
Labcon LTI Low Temperature Incubator	Lab/57B/74	-

2. PROCEDURE / METHOD

- Procedure used: HUM-01
- The Unit Under Test (UUT) was calibrated in accordance with the manufacturer's performance verification procedure in the service manual

3. REMARKS

- **Traceability**
  The accuracy of the equipment used during calibration is traceable to the National Measuring Standards as maintained in RSA or International Measuring Standards.

- **Calibration Environment**
  The calibration was performed in an environmentally controlled laboratory.
  The average atmospheric pressure during the calibration was 850 mBar ±100 mBar.
  The Temperature at time of Calibration was: 22.9°C.
  The Relative Humidity at time of Calibration was: 58%rh

- **Results**
  The UUT conforms to the manufacturer's accuracy specifications.

- **Uncertainty of Measurement (UOM)**
  The reported uncertainty of measurements are based on a standard uncertainty multiplied by a coverage factor of k = 2, which unless specifically stated otherwise, provide a level of confidence of approximately 95 %.

Signed: ________________ Certificate No: 1546-11501

J.L Steinberg
Technical Signatory (Humidity)

4. RESULTS

Note: - Humidity uncertainties are only valid when measurements are made from lower to the higher humidity values.
- The values in this certificate will no longer be valid or applicable if the "calibration function and / or key of the UUT has been activated.

Humidity Calibration					
rh Value (%rh)	Actual Temperature (°C)	Actual Humidity (%rh)	UUT Indicated Humidity (%rh)	UUT Correction (%rh)	UOM (±%rh)
11	23.1	10.9	12.6	-1.7	2.0
53	23.4	53.5	55.0	-1.5	2.0
75	23.0	75.7	79.6	-3.9	2.0

It is unlikely that the error on indicated values would exceed ±1°C

Temperature Calibration				
Temperature Setting (°C)	Actual Temperature (°C)	UUT Indicated Temperature (°C)	UUT Correction (°C)	UOM (±°C)
10	10.0	11.3	-1.3	1.0
50	50.0	48.1	+1.9	1.0
90	90.0	88.1	+1.9	1.0

Functional Test	
Function Tested	Pass / Fail
Hold / Min / Max	Pass
T 1/ T1 / td	Pass
Print	Not Tested

*** End of Results ***

Signed:

J.L. Steinberg
Technical Signatory (Humidity)

Certificate No: 1546-11501

APPENDIX C: TEST RESULTS

Station A

Table C-1: Station A: Forced drying measurements

Date: 15/12/2011 Time	Measured T (°C)	Corrected T (°C)	Measured RH (%)	Corrected RH (%)	Instrument Td (°C)	Calculated Td (°C)
08:48	30.4	29.5	38.6	40.0	12.2	14.8
08:50	31.1	30.2	26.2	26.6	9.2	9.2
08:51	33.2	32.3	22	22.0	7.9	8.3
08:52	34.7	33.8	19.8	19.5	7.4	7.8
08:55	36.6	35.7	19.9	19.6	8.9	9.5
08:56	37.2	36.3	21	20.9	10.3	10.9
08:57	36.8	35.9	25.6	25.9	14.1	13.8
08:58	37.9	37.0	30.7	31.5	17.3	17.8
08:59	38.1	37.2	29.6	30.3	16.9	17.4
09:01	38.1	37.2	25.9	26.3	14.7	15.1
09:04	37.9	37.0	21.8	21.7	11.5	12.1
09:06	37.8	36.9	16	15.3	6.3	6.8
09:07	37.8	36.9	15.6	14.8	5.8	6.4
09:08	37.8	36.9	15.6	14.8	5.8	6.4
09:10	37.8	36.9	15.1	14.3	5.2	5.8
09:12	37.7	36.8	14.3	13.4	4.3	4.8
09:14	37.5	36.6	12.6	11.5	2	2.5
09:18	37	36.1	16.1	15.4	5.8	6.3
09:20	36.5	35.6	14.5	13.6	3.7	4.1
09:24	36.1	35.2	13.4	12.4	2	2.4
09:26	35.7	34.8	13.6	12.6	1.9	2.4
09:28	35.3	34.4	13.3	12.3	1.2	1.7
09:30	35	34.1	13.6	12.6	1.4	1.8
09:33	34.7	33.8	14	13.0	1.6	2.1
09:36	34.3	33.4	14.3	13.4	1.7	2.1
09:39	33.9	33.0	14.3	13.4	1.4	1.8
09:42	33.6	32.7	14.3	13.4	1	1.5
09:45	33.3	32.4	14.1	13.2	0.7	1.1
09:48	32.9	32.0	14.3	13.4	0.6	1.0
09:51	32.8	31.9	14.3	13.4	0.5	0.9
09:55	32.4	31.5	14.6	13.7	0.5	0.9

Station B

Table C-2: Station B: Vacuum drying measurements test 1

Date: 23/11/2011 Time	Measured T (°C)	Corrected T (°C)	Measured RH (%)	Corrected RH (%)	Instrument Td (°C)	Calculated Td (°C)
20:17	26.7	27.1	43.5	42.5	14.1	13.6
20:22	26.7	27.1	51.7	50.5	16	16.2
20:25	26.9	27.4	57.8	56.2	18.1	18.1
20:30	27.1	27.6	63.3	61.3	19.6	19.6
20:34	27.3	27.8	67.8	65.4	20.9	20.9
20:37	27.6	28.1	69.5	66.9	21.5	21.5
20:40	27.8	28.3	70.1	67.5	21.8	21.9
20:45	28.1	28.7	70.2	67.6	22.2	22.2
20:50	28.3	28.9	70.5	67.8	22.4	22.5
20:55	28.5	29.1	70.6	67.9	22.6	22.7
21:00	28.6	29.2	69.8	67.2	22.5	22.7
21:05	28.5	29.1	69	66.5	22.3	22.4
21:10	28.5	29.1	68.5	66.0	22.1	22.3
21:15	28.5	29.1	68.7	66.2	22.2	22.3
21:20	28.4	29.0	68.7	66.2	22.1	22.2
21:25	28.3	28.9	68.9	66.4	22	22.1

Table C-3: Station B: Vacuum drying measurements test 2

Date: 12/01/2013 Time	Measured T (°C)	Corrected T (°C)	Measured RH (%)	Corrected RH (%)	Instrument Td (°C)	Calculated Td (°C)
	22.6	22.6	61.2	59.4	14.9	14.4
05:45	35.9	37.1	33.6	32.7	12.7	18.5
05:47	39.0	40.4	82.9	78.7	37.3	36.2
05:50	40.0	41.5	100.0	100.0	42.0	41.5
05:53	41.0	42.6	100.0	100.0	43.0	42.6

Station C

Table C-4: Station C: Boil drying measurements

Date: 04/10/2012 Time	Measured T (°C)	Corrected T (°C)	Measured RH (%)	Corrected RH (%)	Instrument Td (°C)	Calculated Td (°C)
08:38 (next day)	36.4	35.5	98.4	100.0	33	35.5
08:48	39.5	38.6	83.7	86.0	35.9	35.9
09:01	39.7	38.8	86.1	88.3	36.5	36.6
09:10	40	39.1	85.8	88.0	36.9	36.8
09:21	39.9	39.0	90.2	92.3	37.6	37.6
09:28	39.7	38.8	91.7	93.7	37.6	37.6

Station D

Results for the test conducted at Power Station D making use of forced drying method are presented below.

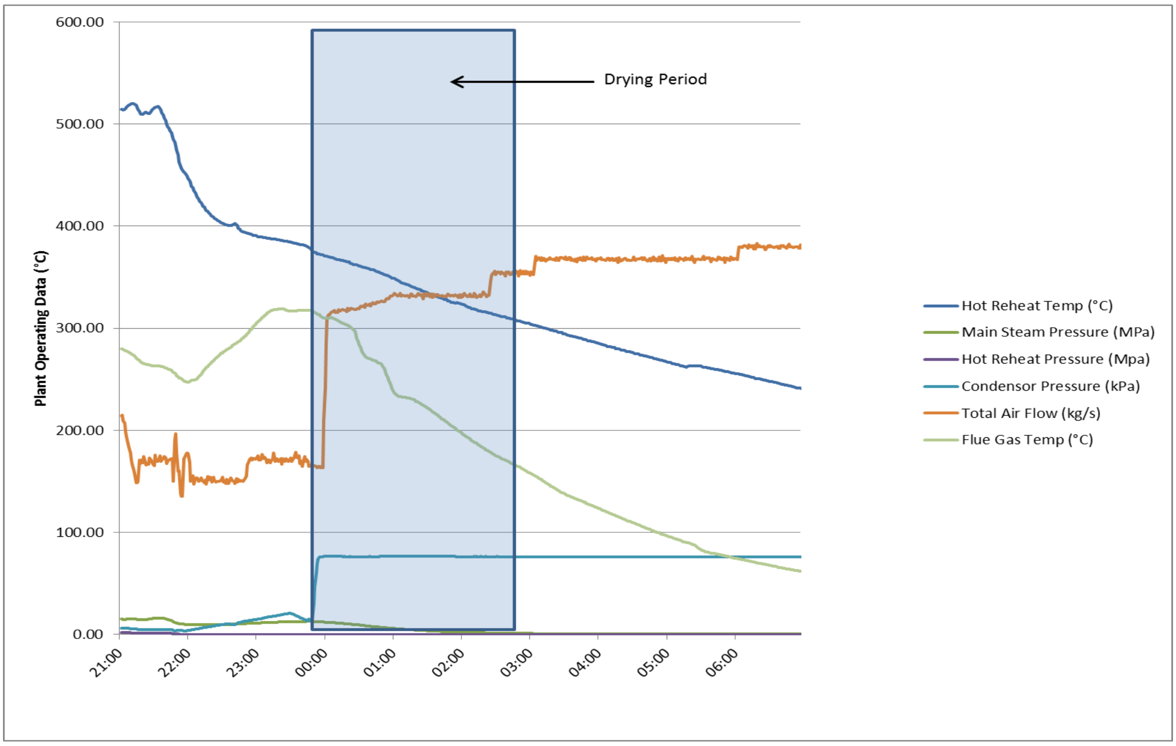

Figure C-1: Plant data for Power Station D forced drying test

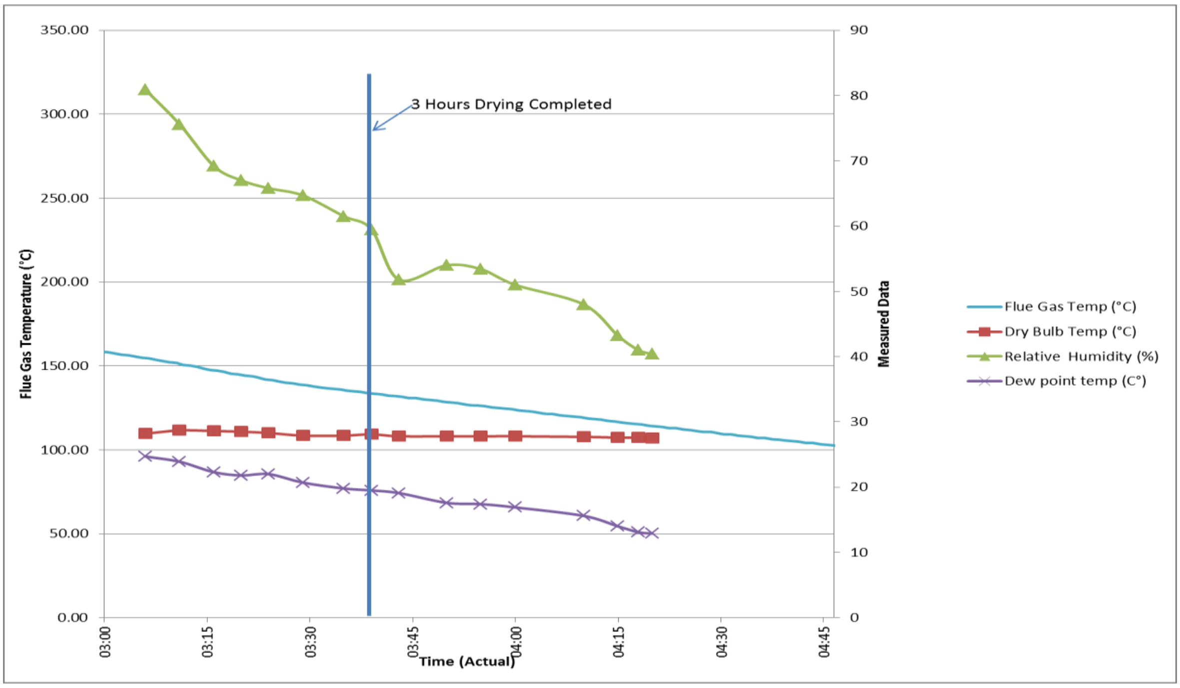

Figure C-2: Test data at Power Station D

The plant operating data show that during drying the flue gas temperature remained above 100 °C, thus no condensation took place. This power station makes use of a 500 kPa compressor. After 3 hours of drying the dew point temperature was 19.6 °C which was below the ambient dry bulb temperature indicating that no condensation would take place if it was left in this state and ambient conditions did not change. After a further hour of drying dew point temperatures dropped further to a low 13.1 °C.

Table C-5: Station D – Forced Drying Measurements

Date: 24/05/2012 Time	Measured T (°C)	Corrected T (°C)	Measured RH (%)	Corrected RH (%)	Instrument Td (°C)	Calculated Td (°C)
03:06	29.1	28.2	78.5	80.9	24.7	24.6
03:11	29.6	28.7	73.1	75.6	23.9	24.0
03:16	29.5	28.6	66.7	69.2	22.3	22.5
03:20	29.4	28.5	64.5	67.0	21.8	21.9
03:24	29.2	28.3	63.3	65.8	22	21.4
03:29	28.9	27.9	62.3	64.7	20.7	20.8
03:35	28.9	27.9	59.1	61.5	19.8	20.0
03:39	29	28.1	57.2	59.5	19.5	19.6
03:43	28.8	27.8	49.8	51.9	19.1	17.3
03:50	28.8	27.8	51.9	54.0	17.6	17.9
03:55	28.8	27.8	51.3	53.4	17.4	17.7
04:00	28.8	27.8	49	51.0	16.9	17.0
04:10	28.7	27.7	46.1	48.0	15.6	16.0
04:15	28.6	27.6	41.6	43.2	14	14.3
04:18	28.6	27.6	39.5	41.0	13.1	13.4
04:20	28.5	27.5	39	40.4	12.9	13.2

Station E

Results for the test conducted at Power Station E making use of forced drying method are presented below.

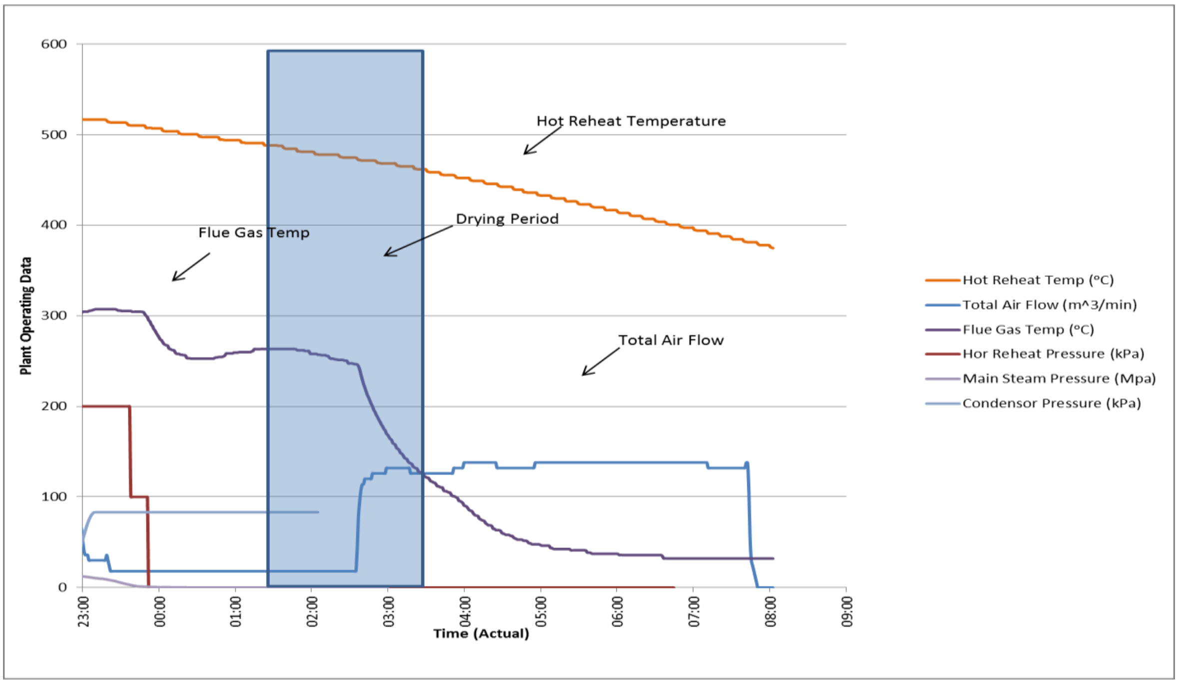

Figure C-3: Plant data for Power Station E forced drying test

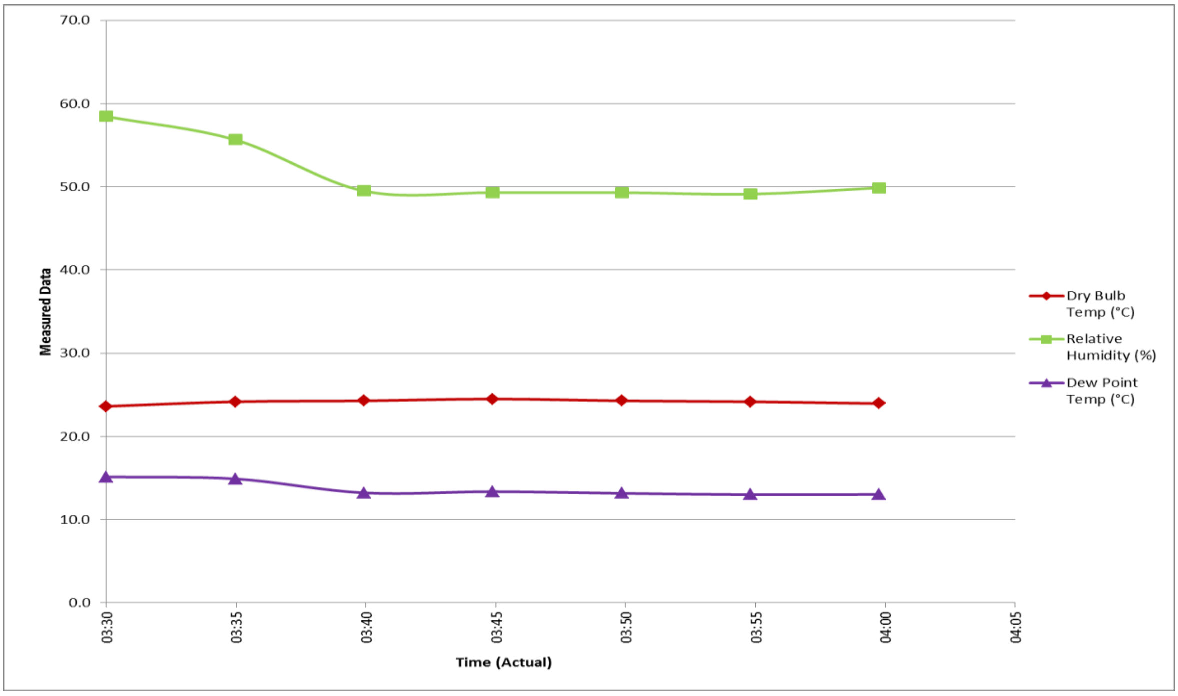

Figure C-4: Test Data for Power Station E

The plant operating data show that during drying the flue gas temperature remained above 100 °C, thus no condensation took place. This power station makes use of a 180 kPa compressor. After 2 hours of drying the dew point temperature was 13 °C which was below the ambient dry bulb temperature indicating that no condensation would take place if it was left in this state and ambient conditions did not change. The ambient dew point temperature was 13.9 °C suggesting that the steam inside the reheaters was replaced with ambient air.

Table C-6: Station E – Forced Drying Measurements

Date: 14/12/2012 Time	Measured T (°C)	Corrected T (°C)	Measured RH (%)	Corrected RH (%)	Instrument Td (°C)	Calculated Td (°C)
Ambient	18.7	18.3	79.1	75.4	15	13.9
03:30	23.5	23.6	60.2	58.4	15.4	15.1
03:35	24	24.2	57.2	55.6	15.1	14.9
03:40	24.1	24.3	50.7	49.5	13.3	13.2
03:45	24.3	24.5	50.5	49.3	13.2	13.4
03:50	24.1	24.3	50.5	49.3	13.2	13.2
03:55	24	24.2	50.3	49.1	13	13.0
04:00	23.8	23.9	51.1	49.9	13.1	13.0

Station F

Results for the test conducted at Power Station F making use of vacuum drying method are presented below.

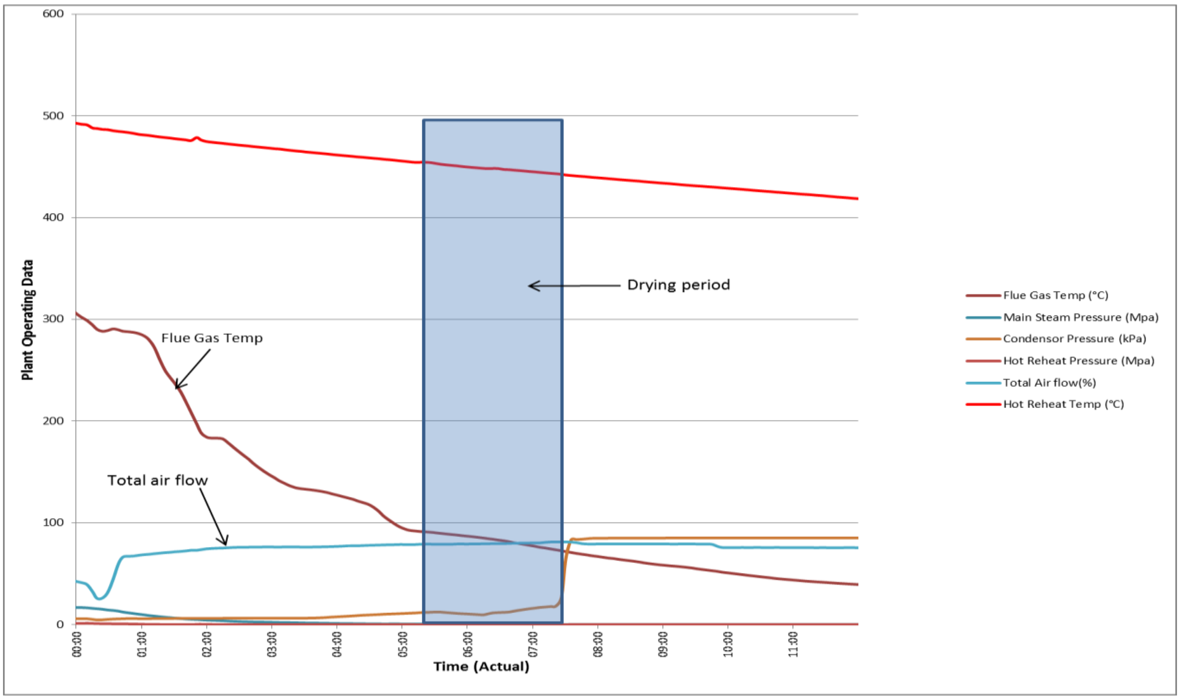

Figure C-5: Plant data for Power Station F vacuum drying test

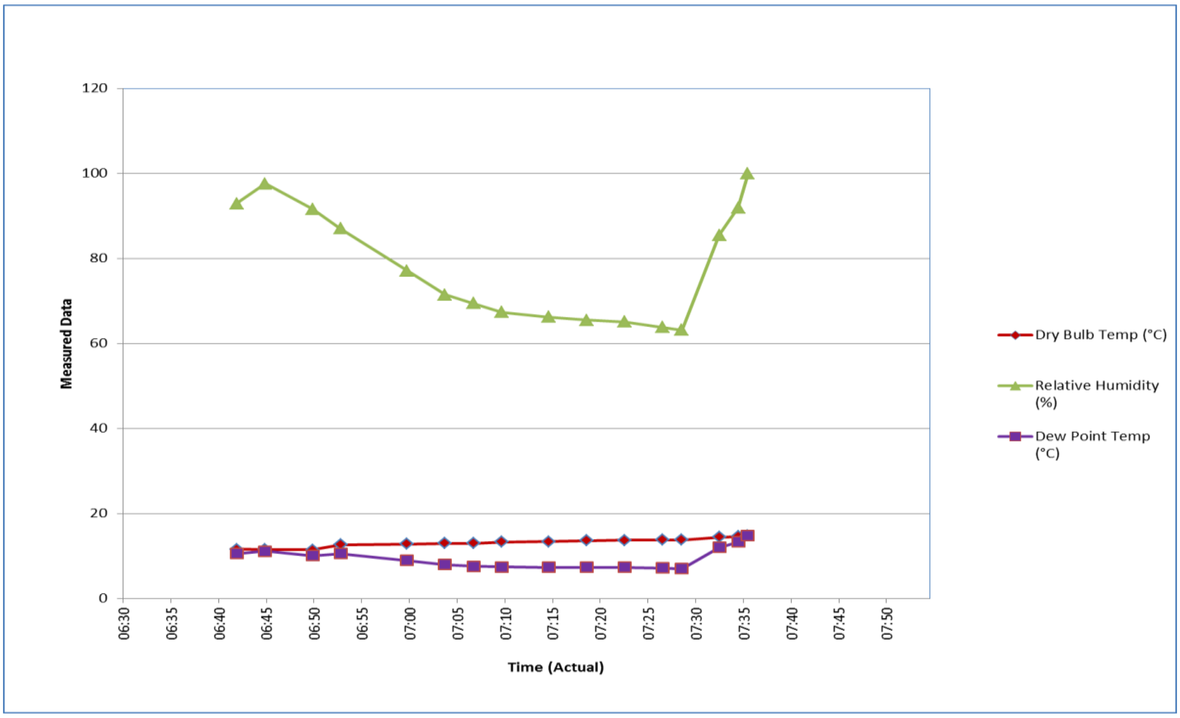

Figure C-6: Test data for Power Station F

The plant operating data show that during drying the flue gas temperature dropped below 100 °C because of boiler force cooling which is part of this power stations procedure. This power station makes use of the condenser vacuum to draw out the steam in the reheaters and replace with air entering from an air inlet valve. Initially while drying took place, the dew point and humidity were decreasing but as soon as the condenser vacuum was broken, indicating drying was completed, a representative sample of the fluid in the reheater was drawn out which had a relative humidity of 100% and dew point of 14 °C indicating an ineffective drying. The reason as to why the measurements initially dropped was that the small portable vacuum pump could not significantly draw against the condenser vacuum.

Table C-7: Station F – Vacuum Drying Measurements

Date: 01/06/2012 Time	Measured T (°C)	Corrected T (°C)	Measured RH (%)	Corrected RH (%)	Instrument Td (°C)	Calculated Td (°C)
05:15:00	13.4	11.8	58.4	60.8	4.5	4.5
05:20:00	13.6	12.0	61.5	63.9	5.7	5.4
05:49:00	13.9	12.3	61.5	63.9	5.4	5.7
05:54:00	13.8	12.2	63.4	65.9	6.5	6.0
05:59:00	13.8	12.2	86.8	89.0	8.3	10.4
06:02:00	13.6	12.0	96.9	98.6	14.1	11.8
06:42:00	13.3	11.7	90.9	92.9	10.7	10.6
06:45:00	13.2	11.5	95.8	97.6	12.3	11.2
06:50:00	13.1	11.4	89.5	91.6	12.60	10.1
06:53:00	14.2	12.6	84.7	87.0	10.4	10.5
07:00:00	14.4	12.8	74.6	77.1	8.8	9.0
07:04:00	14.6	13.0	68.9	71.4	8	8.0
07:07:00	14.6	13.0	66.9	69.4	7.5	7.6
07:10:00	14.8	13.3	64.8	67.3	7.4	7.4
07:15:00	14.9	13.4	63.7	66.2	7.2	7.2
07:19:00	15.1	13.6	63	65.5	7.2	7.3
07:23:00	15.2	13.7	62.7	65.1	7.3	7.3
07:27:00	15.3	13.8	61.4	63.8	7	7.1
07:29:00	15.3	13.8	60.7	63.1	7	7.0
07:33:00	15.9	14.4	83.2	85.5	11.8	12.1
07:35:00	16.1	14.6	89.8	91.9	13.5	13.3
07:36:00	16.3	14.8	98.3	99.9	13.8	14.8

Station G

Results for the test conducted at Power Station G making use of vacuum drying method are presented below.

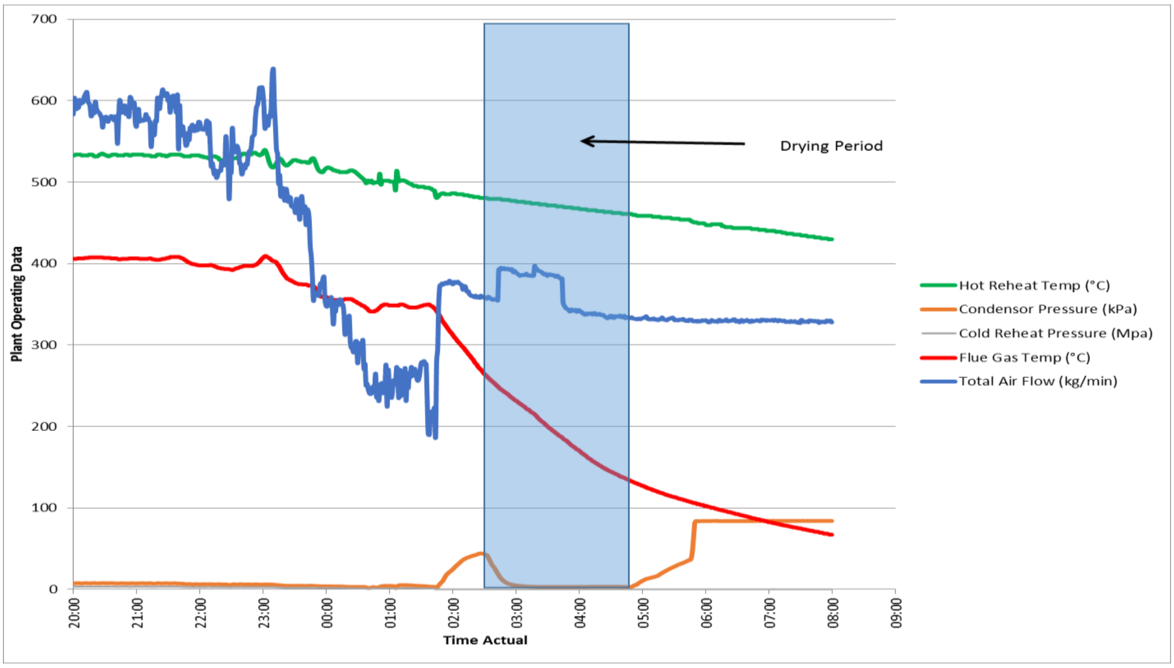

Figure C-7: Plant data for Power Station G vacuum drying test

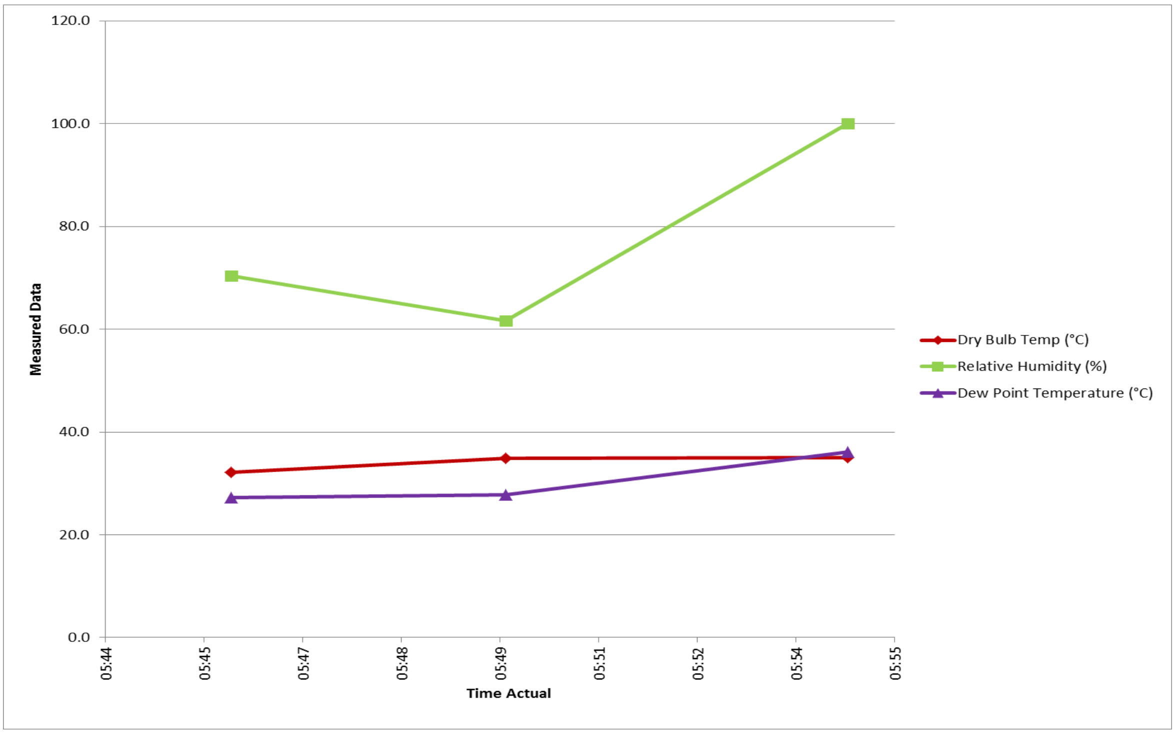

Figure C-8: Test data for Power Station G

The plant operating data show that during drying the flue gas temperature was above 100 °C even though boiler force cooling took place. This power station makes use of the condenser vacuum to draw out the steam in the reheaters and replace with air entering from an air inlet valve. Measurements were only taken after the drying when the condenser vacuum was broken, as the portable vacuum pump could not draw against the condenser. Soon after measurements were taken, condensation took place in the test box and the test was terminated to protect the equipment. The condensation in the box signifies that drying was ineffective.

Table C-8: Station G – Vacuum Drying Measurements

Date: 05/03/2013 Time	Measured T (°C)	Corrected T (°C)	Measured RH (%)	Corrected RH (%)	Instrument Td (°C)	Calculated Td (°C)
Ambient	35.0	36.2	21.8	20.6	10.1	10.6
05:46 AM	32.2	33.1	73.4	70.4	37.3	27.2
05:50 AM	34.9	36.0	63.7	61.7	42.0	27.7
05:55 AM	35.0	36.2	100.0	100.0	43.0	36.2

APPENDIX D: PSYCHROMETRIC CHART

A psychrometric chart is shown in Figure D-1. Taking a point on the graph on the 50% relative humidity mark the dew point, wet bulb temperature, dry bulb temperature and humidity ratio are shown for the specific point. It can be seen that if the point is moved along a horizontal line the dew point temperature and humidity ratio do not change. These are functions of water content only. The relative humidity is a function of the temperature and will change as the point is moved in a horizontal plane. The basis of comparing the results is thus chosen to be the dew point temperature and not just the relative humidity.

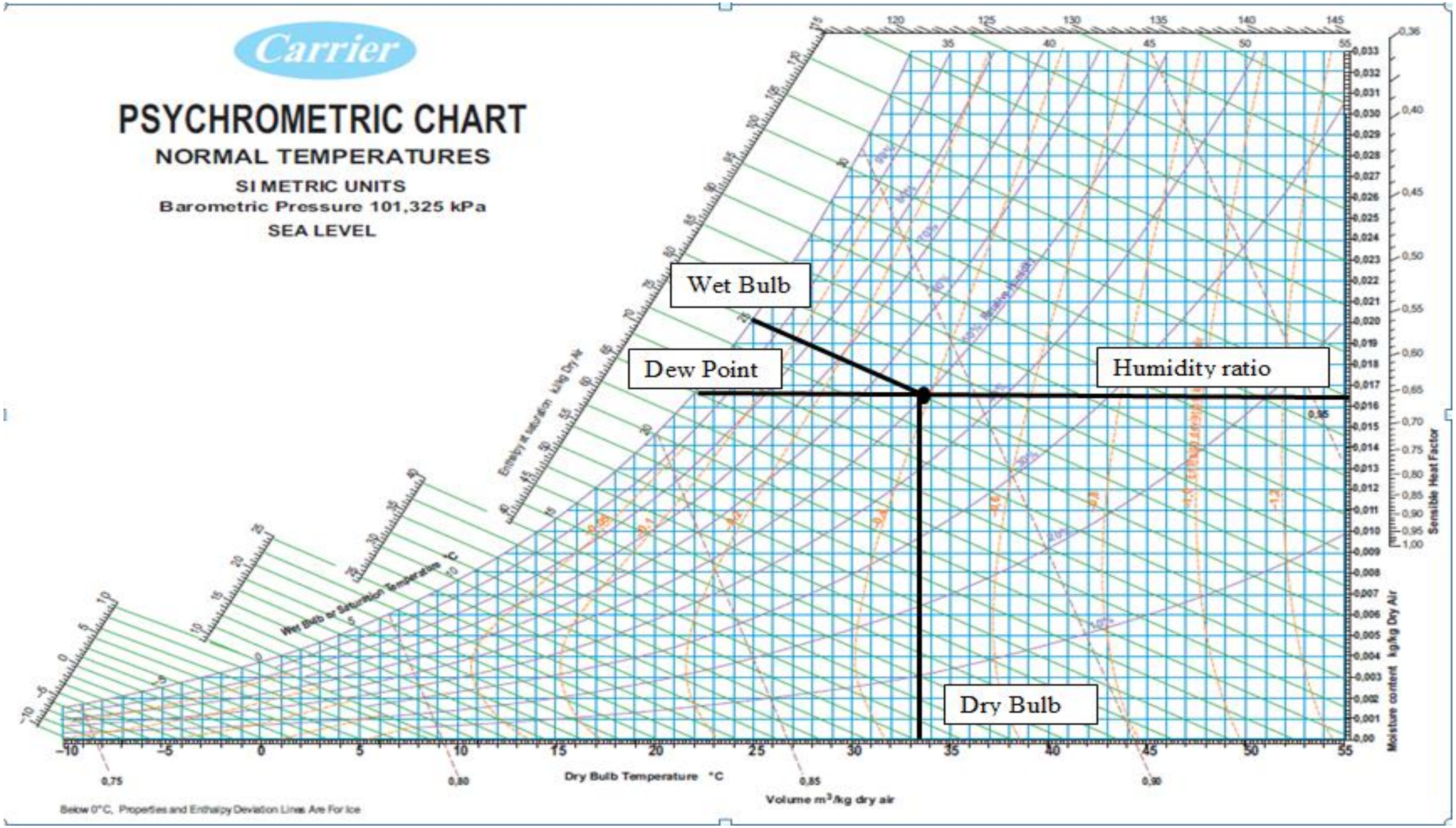

Figure D-1: Psychrometric chart [57]

APPENDIX E: FLOW CALCULATIONS

Volumetric and mass flow at Power Stations B and E are calculated below. Power Stations B and E have exactly the same design with regards to the boiler. Power Station B makes use of vacuum drying while Power Station E makes use of forced drying. Under normal operating shut down, the system temperatures and pressures are the same at the time reheater drying commences. To compare the two different drying methods used, the flow rate for the system is calculated. The following assumptions are made for simplifying the calculation.

- The flow rate is calculated in a steam free cold environment with the air inlet temperature of 25°C. The 3 intercoolers within the compressor at Power Station E also provides pressurised air at the same temperature as atmospheric temperature
- The average density between the inlet and outlet is used
- The effects of gravity are negligible as the inlet and outlet are close to the 15 m level of the boiler house
- Equal flow distribution through the reheater tubes
- The fluid flowing through the system is dry air

Figure E-1 below depicts a simplified diagram of the system showing the major components affecting the pressure drop.

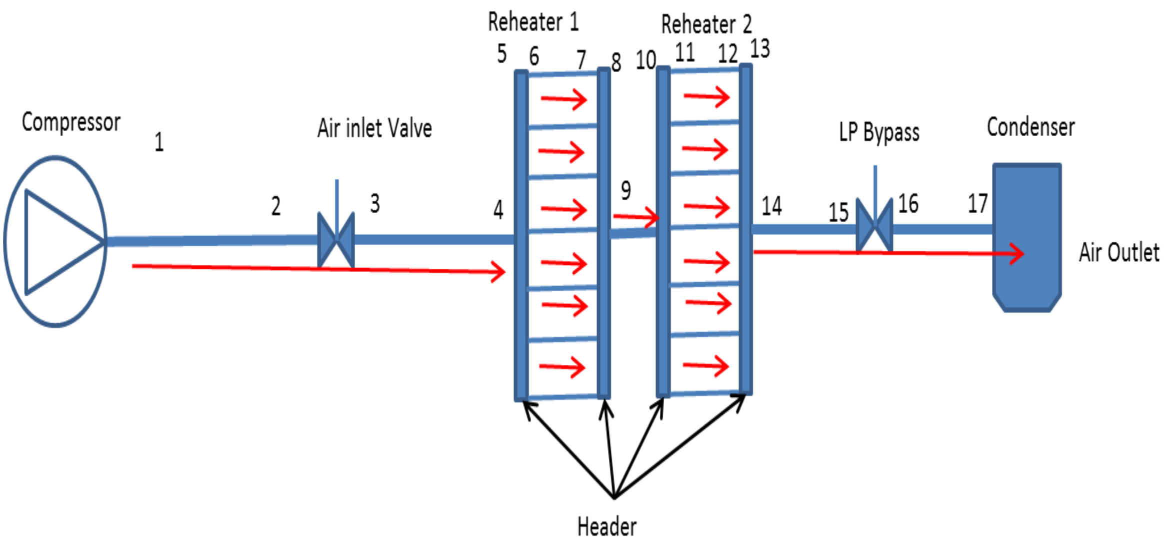

Figure E-1: Flow Diagram for Power Stations B and E

The flow diagram shows that air flows from the atmosphere (under vacuum drying) or the compressor (under forced drying) through the air inlet valve, into the reheater 1 header where the flow splits equally into the tubes. Air collects into the reheater 1 outlet header and into the reheater 2 inlet header. Again, the flow splits equally through the tubes where it collects into the reheater 2 outlet header, through the cold reheat pipe through the LP bypass valve and exhausts into the condenser, through the cold reheat pipe through the LP bypass valve and exhausts into the condenser.

An iterative method is used to calculate the volumetric flow rate by assuming a velocity and calculating the pressure drop through each component. The sum of the pressure drops equals the total pressure drop between the inlet and the outlet. The following equations were used to determine the flow rate [53].

Equation E-1: Pressure Drop through Pipe

$$\Delta P = \frac{2f\rho V^2 L}{D}$$

Where:

ΔP is the Pressure Drop (Pa)
f is the Fanning Friction factor
ρ is the density of the fluid (kg/m^3)
V is the velocity (m/s)
L is the length of the pipe (m)
D is the diameter of the pipe (m)

Equation E-2: Reynolds number

$$Re = \frac{DV\rho}{\mu}$$

Where:

Re is the Reynolds number
μ is the absolute viscosity of the fluid

The fanning friction factor f is a function of the Reynolds number and the relative roughness of the pipe is ε/D where ε is the surface roughness of a pipe in mm.

Equation E-3 [53] provides a good correlation for f for rough pipes over the entire turbulent flow range, Re > 4000

Equation E-3: Frictional Factor

$$\frac{1}{\sqrt{f}} = -4log\left[\frac{0.27\epsilon}{D} + \left(\frac{7}{Re}\right)^{0.9}\right]$$

The pressure drop when the fluid contracts into a smaller pipe or expands into a larger pipe is given by Equation E-4.

Equation E-4: Pressure drop through expansion and contraction

$$\Delta P = K\frac{\rho V^2}{2}$$

Where:

K is the velocity head loss coefficient

The velocity head loss coefficient K is approximated for turbulent flow by Equation E-5 for contraction.

Equation E-5: K for contraction

$$K = 0.5\left(1 - \frac{A_2}{A_1}\right)$$

Where:

A_1 is the area of the smaller pipe

A_2 is the area of the larger pipe

The frictional losses f_e for expansion is approximated for turbulent flow by Equation E-6.

Equation E-6: *f* for expansion

$$f_e = \frac{V^2}{2}\left(1 - \frac{A_1}{A_2}\right)^2$$

The frictional losses f for flow through a valve is given by a K value specific to the valve type and position open of the valve. The pressure loss is calculated as mentioned above in Equation E-1.

The density of the fluid is calculated by Equation E-7 below.

Equation E-7: Density of Air

$$\rho = \frac{P}{R_{Air}T}$$

Where:

P is the pressure of the fluid (Pa)

R_{air} is the gas constant for dry air (287.058 J/kg.K)

T is the temperature of the fluid (K)

Table E-1 below shows all the input data for calculating the fluid flow.

Table E-1: Input data for flow calculations

Atmospheric pressure	83000 Pa
Dry Air Temperature	25°C
Forced cooling pressure	263000 Pa(g)
Condenser pressure	12500 Pa(a) (Average condenser pressure during drying)
Total ΔP (Forced)	180000 Pa
Total ΔP (Vacuum)	70500 Pa
Average air density (Forced)	2.02 kg/m^3
Average air density (Vacuum)	0.56 kg/m^3
Ɛ (Roughness of Commercial Steel)	0.0457
K (Air inlet gate valve ¾ open) [53]	0.9
K (LP Bypass gate valve ½ open) [53]	4.5
Air inlet pipe dimensions (L x ID)	90m x 0.15m
Cold Reheat pipe dimension (L x ID)	166.857m x 0.674
Reheater 1 tube dimensions (L x ID)	68m x 0.0428m
Number of reheater 1 tubes	1280
Reheater 2 tube dimensions (L x ID)	34.372m x 0.0438m
Number of reheater 2 tubes	800
RH1 Inlet/Outlet Header dimensions (L x ID)	22m x 0.67m
RH2 Inlet/Outlet Header dimensions (L x ID)	22.151m x 0.53m

As mentioned an iterative process is followed by guessing a velocity value at the inlet and computing the pressure drops along the system. Thereafter adjusting the inlet velocity value until the sum of the pressure drop equates the total pressure drop for each method of drying. The results are tabulated below in Table E-2 with detail calculations shown thereafter.

Table E-2: Flow rates calculated at average air density

	Vacuum Drying (Power Station B)	**Forced Drying (Power Station E)**
Inlet Velocity (m/s)	17.31	15.84
Volumetric Flow Rate (m^3/min)	18.35	16.79
Mass Flow Rate (kg/min)	10.24	33.94

Forced Drying Calculations

Forced Drying	
Input	
Air Properties	
Temperature (K)	**298.15**
Density (kg/m3)	**2.02**
Dynamic Viscosity (kg/m.s-1)	**1.84E-05**
Inlet Pressure (Compressor Pa)	**263000**
Outlet Pressure (Atmospheric Pa)	**83000**
R (J/kg.K)	**287.058**
Guess Velocity (m2/s)	**15.84**

Position	**1 to 2**	**2 to 3**	**3 to 4**	**4 to 5**	**5 to 6**	**6 to 7**
Description	**Straight Pipe**	**Valve**	**Straight Pipe**	**Expansion into Header**	**Contraction into Tubes**	**Single Tube**
Pipe Internal Diameter (m)	0.15	0.15	0.15	0.67	0.0428	0.0428
Pipe Length (m)	80	1	10	22	68	68
Area (m2)	0.02	0.02	0.02	0.35	0.00	0.00
P1 (Pa)	280000.00	277658.14	271575.90	271283.17	100130.36	100100.73
P2 (Pa)	277658.14	271575.90	271283.17	100130.36	100100.73	100097.87
ΔP (Pa)	2341.86	6082.24	292.73	171152.80	29.63	2.86
Velocity (m/s)	15.84	15.84	15.84	0.79	0.79	0.15
Re	261291.96	261291.96	261291.96	58498.20	3736.90	715.42
K		0.90		113.12	0.50	
f	15.19		15.19			7.20
1/Sqrt f	0.00		0.00			0.02
Volumetric Flow (m3/s)	0.28	0.28	0.28	0.28	0.00	0.00
Volumetric Flow (m3/min)	16.79			16.78974696		0.000441901

Position	**7 to 8**	**8 to 9**	**9 to 10**	**10 to 11**	**11 to 12**
Description	**Expansion into Header**	**Straight Pipe**	**Expansion into Header**	**Contraction into Tubes**	**Single Tube**
Pipe Internal Diameter (m)	0.67	0.53	0.527	0.0428	0.0438
Pipe Length (m)	22.151	5	22.151	68	34.372
Area (m2)	0.35	0.22	0.22	0.00	0.00
P1 (Pa)	100097.87	100097.87	100097.57	100097.57	100022.09
P2 (Pa)	100097.87	100097.57	100097.57	100022.09	100019.39
ΔP (Pa)	0.00	0.30	0.00	75.48	2.70
Velocity (m/s)	0.15	1.27	1.27	1.27	0.23
Re	11199.40	73950.55	73531.97	5971.86	1105.92
K	0.01		0.00	0.50	
f		14.32			7.87
1/Sqrt f		0.00			0.02
Volumetric Flow (m3/s)	0.05	0.28	0.28	0.00	0.00
Volumetric Flow (m3/min)					

Position	**12 to 13**	**13 to 14**	**14 to 15**	**15 to 16**	**16 to 17**
Description	**Expansion into Header**	**Expansion into Pipe**	**Straight Pipe**	**Valve**	**Straight Pipe**
Pipe Internal Diameter (m)	0.53	0.674	0.674	0.674	0.674
Pipe Length (m)	22.151	68	146.857	1	20
Area (m2)	0.22	0.36	0.36	0.36	0.36
P1 (Pa)	100019.39	100019.38	100019.38	100016.67	100000.44
P2 (Pa)	100019.38	100019.38	100016.67	100000.44	100000.08
ΔP (Pa)	0.01	0.00	2.71	16.23	0.37
Velocity (m/s)	0.23	1.25	0.78	0.78	0.78
Re	13382.11	92981.16	57494.58	57494.58	57494.58
K	0.03	0.00		4.50	
f			13.99		13.99
1/Sqrt f			0.01		0.01
Volumetric Flow (m3/s)	0.05	0.28	0.28	0.28	0.28
Volumetric Flow (m3/min)					

Output	
ΔP (Pa) Inlet to Outlet Calculated	**-180000.00**
ΔP (Pa) Inlet to Outlet Set	**-180000.00**
Mass Flow (kg/min)	**33.94**

Vacuum Drying Calculations

Vacuum	
Input	
Air Properties	
Temperature (K)	298.15
Density (kg/m3)	0.56
Dynamic Viscosity (kg/m.s-1)	1.84E-05
Inlet Pressure (Compressor Pa)	83000
Outlet Pressure (Atmospheric Pa)	12000
R (J/kg.K)	287.06
Guess Velocity (m2/s)	17.31

Position	1 to 2	2 to 3	3 to 4	4 to 5	5 to 6	6 to 7	7 to 8	8 to 9	9 to 10	10 to 11	11 to 12	12 to 13	13 to 14	14 to 15	15 to 16	16 to 17
Description	Straight Pipe	Valve	Straight Pipe	Expansion into Header	Contraction into Tubes	Single Tube	Expansion into Header	Straight Pipe	Expansion into Header	Contraction into Tubes	Single Tube	Expansion into Header	Expansion into Pipe	Straight Pipe	Valve	Straight Pipe
Pipe Internal Diameter (m)	0.15	0.15	0.15	0.67	0.04	0.04	0.67	0.53	0.53	0.04	0.04	0.53	0.67	0.67	0.67	0.67
Pipe Length (m)	80.00	1.00	10.00	22.00	68.00	68.00	22.15	5.00	22.15	68.00	34.37	22.15	68.00	146.86	1.00	20.00
Area (m2)	0.02	0.02	0.02	0.35	0.00	0.00	0.35	0.22	0.22	0.00	0.00	0.22	0.36	0.36	0.36	0.36
P1 (Pa)	83000.00	82096.31	80090.59	79977.63	12544.77	12535.00	12533.29	12533.29	12533.16	12533.16	12508.27	12506.75	12506.75	12506.75	12505.57	12500.22
P2 (Pa)	82096.31	80090.59	79977.63	12544.77	12535.00	12533.29	12533.29	12533.16	12533.16	12508.27	12506.75	12506.75	12506.75	12505.57	12500.22	12500.06
ΔP (Pa)	903.69	2005.72	112.96	67432.86	9.77	1.71	0.00	0.13	0.00	24.89	1.52	0.00	0.00	1.18	5.35	0.16
Velocity (m/s)	17.31	17.31	17.31	0.87	0.87	0.17	0.17	1.39	1.39	1.39	0.25	0.25	1.37	0.85	0.85	0.85
Re	78830.34	78830.34	78830.34	17648.58	1127.40	215.84	3378.80	22310.47	22184.19	1801.68	333.65	4037.31	28051.90	17345.80	17345.80	17345.80
K		0.90		135.15	0.50	0.00	0.01	0.01	0.00	0.50	-0.02	0.03	0.00		4.50	
f	14.05		14.05	12.21	7.90	5.35	9.65	12.56	12.55	8.61	6.03			12.18		12.18
1/Sqrt f	0.01		0.01	0.01	0.02	0.03	0.01	0.01	0.01	0.01	0.03			0.01		0.01
Volumetric Flow (m3/s)	0.31	0.31	0.31	0.31	0.31	0.00	0.06	0.31	0.30	0.00	0.00	0.06	0.30	0.30	0.30	0.30
Volumetric Flow (m3/min)	18.35	18.35	18.35	18.35	18.35	0.01	3.51	18.35	18.14	0.12	0.02	3.32	18.14	18.14	18.14	18.14

Output	
ΔP (Pa) Inlet to Outlet Calculated	-70499.94
ΔP (Pa) Inlet to Outlet Set	-70500.00
Mass Flow (kg/min)	10.24