University of Southern Queensland

Faculty of Engineering and Surveying

The Formation of Nitrogen Oxides

in a Pulverised Coal Boiler

A dissertation submitted by

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Abstract

The oxides of nitrogen (NO_x) are airborne pollutants that result from the combustion of pulverised coal. The aim of this project is to identify operational methods that reduce the NO_x emissions from a coal fired boiler whilst maintaining satisfactory performance.

This project describes important combustion properties and the processes occurring during the combustion of pulverised coal. Detail is provided on the pulverisation plant, draught plant and steam system of a large utility boiler. The dominant NO_x formation mechanisms in coal fired boilers are discussed and NO_x reduction strategies applicable to these boilers are described. Engineering models are developed to describe initial flame temperature, furnace residence times, furnace heat pickup and thermal NO_x formation.

A series of tests were designed and undertaken to measure and assess the effect on NO_x formation and boiler performance to variations in:-

- The distribution of secondary air to each windbox, and
- The level of excess oxygen measure at the boiler exit.

During each test the following was undertaken:-

- Detailed temperature survey of the furnace region
- Coal sampling for laboratory analysis
- Fly Ash sampling to determine loss of ignition
- Logs of relevant data to determine plant performance

Difficulties and shortcomings regarding the predictive models are discussed and the performance of the boiler under each test is compared.

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Date

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Table of Contents

2   ENVIRONMENTAL & ECONOMIC CONSIDERATIONS

3   COAL ANALYSIS AND BOILER PLANT

4   COAL COMBUSTION PRINCIPLES

List of Figures

List of Tables

Glossary

adb	Air Dried Basis
AGC	Automatic governor control
ALNB	Advanced low NO_x burners
ASTM	American Society for Testing and Materials
BLSP	Boiler load set point
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CV	Calorific value
C_xH_y	Miscellaneous Hydrocarbons
daf	Dry ash free
EPRI	Electric Power Research Institute
H_2	Hydrogen
H_2O	Water (Liquid or Vapour)
LOI	Loss of Ignition
N_2	Diatomic Nitrogen
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
O	Monatomic Oxygen
O_2	Diatomic Oxygen
OFA	Over Fire Air
PF	Pulverised Fuel
RPM	Revolutions per minute
SCR	Selective catalytic reduction
SE	Specific Energy
SNCR	Selective non catalytic reduction

Introduction

1.1   Introduction

Australia is highly dependent on fossil fuels for the production of electricity with the Australian Bureau of Statistics (1999) reporting 89% of electricity is generated from the burning of coal. There are numerous pollutants created from the combustion of coal which include carbon dioxide (CO_2), sulphur dioxide (SO_2) as well as nitric oxide (NO) and nitrogen dioxide (NO_2) which are collectively known as NO_x.

This project concentrates on gaining an understanding of the factors contributing to NO_x emissions and investigates how variations in operational parameters affect the emissions. The testing component of the project was undertaken on a 350 megawatt (MW) coal fired boiler at Stanwell Power Station in Central Queensland.

Even though there is an emergence of environmentally friendly power generation methods, namely geothermal and tidal as well as the existing "green" methods of hydro, solar and wind, Australians will continue to rely on coal for power generation well into the foreseeable future. Therefore this project has particular relevance in today's environmentally conscious society.

1.2   Statement of Problem

The formation of NO_x is an inevitable result of burning pulverised coal due to inherent nitrogen in both the fuel and in the air used to support combustion. There are numerous techniques available to reduce NO_x emissions, with many of these techniques involving substantial capital investment.   This project investigates operational methods, that is, those that do not involve capital investment or modification to plant, to reduce NO_x emissions.

The reduction of NO_x emissions often results in a decline in plant efficiency. This project aims to identify and test the effect on emissions and performance as the boiler is operated under various operational configurations.

1.3   Aim

The aim of this project is to identify and implement different boiler operational configurations and test whether these techniques are effective in the minimisation of NO_x emissions, whilst still satisfying boiler operational requirements.

1.4   Objectives

The objectives to achieve this aim include:-

- Describe coal characteristics and the sequence of processes a coal particle undergoes during combustion in a pulverised fuel (PF) boiler.
- Describe boiler plant operation and limitations including fuel delivery and pulverisation, air, gas and steam plant.
- Determine various combustion properties including stoichiometric air requirements, initial flame temperature, residence time/s and equilibrium combustion products.
- Describe the mechanisms responsible for the formation of NO_x during combustion and use the combustion properties to build a model to predict thermal NO_x production.
- Identify and describe the present methods used in the reduction of NO_x in PF boilers.
- Design and undertake baseline testing of the NO_x produced under present operation. Implement different operational factors and assess any effect on the NO_x produced.

1.5   Overview

1.5.1   Chapter 2 – Environmental and Economic Considerations

Chapter 2 discusses acid pollution and its effect on the environment. It also looks at the Kyoto Agreement and Australia's refusal to ratify the requirements of the Agreement. This Chapter also discusses the economic considerations of enforcing pollution control measures.

1.5.2   Chapter 3 – Coal Analysis and Boiler Plant

Chapter 3 provides details on the ranking of coal by the American Society for Testing and Materials and the various analyses of coal including Proximate Analysis, Ultimate Analysis and Specific Energy. This Chapter also looks at the machinery utilised in boiler plant operations including the water and steam plant, draught plant as well as fuel and combustion plant.

1.5.3   Chapter 4 – Coal Combustion Principles

Chapter 4 details the processes as pulverised coal enters the combustion zone of the furnace. Information is also provided on principles useful when dealing with combustion problems including mole and mass fractions, atom balances and equivalence ratios.

1.5.4   Chapter 5 - NO_X Creation Mechanisms and Control

Chapter 5 discusses the mechanisms responsible for NO_x formation in a pulverised coal boiler specifically fuel NO_x and thermal NO_x. Technology available to limit NO_x emissions from boiler plant are described in detail.

1.5.5   Chapter 6 – Engineering Models

In Chapter 6 a number of engineering models are developed to describe factors influential to NO_x formation and plant performance. These include furnace residence times, flame temperature, furnace heat pickup and thermal NO_x formation.

1.5.6   Chapter 7 – Testing

Chapter 7 describes the variables of interest that were monitored during testing. The apparatus used to measure NO_x emissions, flame temperature and flue gas loss of ignition are described in detail. Other test information including method for determination of excess oxygen, the data used to determine furnace heat pickup and the location of test points throughout the furnace region are described. The set up, specific requirements, assumptions and boiler conditioning requirements for each test are detailed.

1.5.7   Chapter 8 – Results

Chapter 8 compares the results obtained for each of the tests. A series of graphs are created to allow quick comparison of some of the variables of interest. Explanations for discrepancies between predicted and actual values are offered and the positive results coming from the tests are mentioned.

1.5.8   Chapter 9 – Conclusion

Chapter 9 provides a summary of what the project has achieved.

1.6   Risk Assessment

This project involved both field work and office work and there were risks associated with both of these. All testing was carried out at Stanwell Power Station whilst the research and reporting was carried out both in a work and home environment.

Table 1.1 details the control measures undertaken to minimise the identified hazards during the testing stage. Hazards that required management in the research and reporting phase included back and eye strain issues. These hazards were controlled by adopting good posture and taking regular breaks. There was also a risk of losing the data and write ups performed, so multiple copies were kept of important data at all times.

Risk Source	Hazard	Control Measures
Thermal	Burns from furnace exhaust gases	Sleeves to be rolled down, welding gloves and facemasks to be worn while performing tests.
Thermal	Dehydration	Water bottle to be kept on hand.
Noise	Damaged hearing	Suitable hearing protection to be worn at all times.
Kinetic	Foreign objects in eyes	Eye protection to be worn at all times.
Environment	Trips and falls	Ensure adequate lighting is installed at test points.

Table 1.1 – Risk Assessment and Control Measures

Environmental and Economic Considerations

2

2.1   Environmental Impacts

2.1.1   Acid Pollution

Acid pollution is a side effect of our heavy reliance on fossil fuels. Whenever coal, oil or natural gas is burned, sulphur dioxide and nitrogen oxides are released into the atmosphere where they undergo a series of chemical processes that turn them into acids. All rainfall is slightly acidic as a result of sulphur, nitrogen and carbon dioxide occurring naturally in the air, however acidification has become much worse ever since the advent of the industrial revolution (McCormick, 1997).

As McCormick (1997) states, acid pollutants have numerous environmental effects including damaging trees, plants and crops, contributing to the decline in freshwater animal and plant life, acidifying soils, rivers and lakes and not to mention the threat to human health. However the problem exists that "while the general process of acid damage is well established and proven, the mechanisms by which the damage occurs, and the relative contribution of the different components of acid pollution and other natural or man-made factors, are still debated" (McCormick, 1997, p21). This presents a problem for not only scientists but also policymakers as without a clear understanding of how and why the damage occurs, it is difficult to agree on workable policies. As a result, the government and industries are reluctant to finance pollution control measures when there is often no certainty about which pollutants are causing what kind of damage (McCormick, 1997).   Through national and international research programmes, more certain answers are being provided to these questions, however few programmes have been operating for more than 10 to 15 years making it difficult to establish long term trends (McCormick, 1997).

2.1.2 NO_X and the Environment

As mentioned above, NO_X is generated in complex mechanisms during the high temperature combustion of coal, oil and gas fuels. Motor vehicle emissions are the primary producer of NO_X whilst power generation, petrol refining, food

manufacturing, gas and wood heaters, cigarette smoke, lightning storms and bushfires also contribute to the problem. Although not the primary producer of NO_X, the contribution made by electricity generators still accounts for a significant proportion of total NO_X and its overall contribution to global pollution cannot be ignored.

In a coal fired boiler the quantity and composition of the nitrogen oxides depends on how the combustion of the fuel takes place. In general, by lowering the combustion temperature and reducing the time the combustion products reside in the combustion chamber can reduce NO_X formation. By doing so however generally affects the efficiency of the plant. The level of NO_X emissions that power generators can produce are dictated to them by the Environmental Protection Authority under the *Environmental Protection Act 1994.* Power generators have the task of balancing environmental factors versus plant efficiency and economic considerations.

2.2   Economic Considerations

The Kyoto Agreement, signed in the Japanese city of Kyoto in 1997, is aimed at reducing the emissions from carbon based fuels into the atmosphere. It is believed that these emissions as well as the release of other gases is a source of global warming and other changes in the climate worldwide (Hot Enough For You?, 2002). The United States has withdrawn entirely from the Kyoto process even though it is the world's leading contributor of greenhouse gases. Recently, Australian Prime Minister John Howard also refused to ratify the requirements of the Agreement (Howard Stands Firm Against Kyoto, 2004) on the grounds that abiding by the terms of the Agreement would cost jobs and damage the economy through the loss of important markets to non-signatory countries such as Indonesia. Dodson & Gordon (2002, p1) suggest that "ratifying the Kyoto Protocol is seen by the government as imposing the risk of economic penalties on resource exporters, which would not be faced by other countries signing it, such as China and India". This in turn would mean the loss of industries from Australia to countries like China and India that do not have the same restrictions under Kyoto as Australia would have.

It is also reported that the emissions target for Australia under Kyoto is demonstrably tougher than that for most countries. This is due to the increasing prevalence of emissions intensive industries in the Australian economy and because of our relatively fast rate of population growth (Daley, 2000). Much of the industrial plant in Australia was designed with little thought given to emission control as at the time there were no legislative requirements to abide by. Achieving compliance may require implementation of expensive retrofit technology and/or reductions in the capacity of existing plant. These measures effectively increase the price of Australian manufactured goods and services and places Australian based companies, both locally and foreign owned, at an economic disadvantage. This is especially the case given Australia's main competitors do not have any commitments under Kyoto (Daley, 2000).

In reality, pollution control measures equate to additional costs in the production of goods and services and puts Australia at a competitive disadvantage compared to countries refusing to abide by any pollution standards.

Coal Analysis and Boiler Plant

3

3.1   Coal Analysis

3.1.1   Rank

Coal can be divided into two major groups of constituents:-

1.   The parts that when combusted liberate substantial energy in an exothermic reaction; and

2.   Those that do not contribute to the combustion process.

The physical and chemical properties of coal vary for different coals and for convenience the different types are classified by rank. The American Society for Testing and Materials (ASTM) classification system ranks coals according to their fixed carbon content and specific energy. Table 3.1 details the variation of coal properties with ASTM rank.

Class	Group	Fixed Carbon (% dmmf)		Specific Energy (MJ/Kg mmmf)	
		Equal or greater than	Less than	Equal or greater than	Less than
Anthracite	Meta-anthracite	98	...	...	...
	Anthracite	92	98	...	...
	Semi-anthracite	86	92	...	...
Bituminous	Low volatile	78	86	...	...
	Medium volatile	69	78	...	...
	High volatile A	...	69	32.57	...
	High volatile B	...	...	30.24	32.57
	High volatile C	...	...	26.75	30.24
Sub-bituminous	Sub-bituminous A	...	...	24.42	26.75
	Sub-bituminous B	...	...	22.10	24.42
	Sub-bituminous C	...	...	19.31	22.10
Lignite	Lignite A	...	...	14.65	19.31
	Lignite B	...	...	...	14.65

Table 3.1 – ASTM Classification of Coal by Rank
(Source: Juniper, 1999, p7)

3.1.2   Proximate Analysis

The proximate analysis of coal determines the quantity of moisture, ash, volatile matter and fixed carbon in a coal sample. These quantities are determined gravimetrically and involve the following steps:-

1. The air dried moisture content is determined by spreading out the sample and allowing it to dry in the lab atmosphere. A moisture determination is then carried out by heating the sample to between 105°C and 110°C in an atmosphere of nitrogen.

2. The ash content is the inorganic residue of the sample after it is incinerated at 815°C in an atmosphere containing excess oxygen.

3. The volatile matter is determined as the loss in mass, corrected for moisture, which occurs when the sample is heated in an inert atmosphere to a temperature of 900°C for seven minutes.

4. The fixed carbon content is calculated by subtracting the total of the percentages of the air dried moisture, ash and volatile matter.

3.1.3   Ultimate Analysis

The ultimate analysis is performed to determine the main organic constituents in the coal and is reported on a mass basis. Various standard laboratory procedures are used to obtain quantities of carbon, hydrogen, nitrogen and sulphur with the oxygen content taken as the balance of the elements.

3.1.4   Specific Energy

The specific energy (SE) refers to the amount of energy that is liberated during combustion per unit mass of coal. There are two ways to express the specific energy, the Gross SE and the Net SE, the difference being the amount of heat required to evaporate the water already present in the coal as well as the water formed from the combustion of hydrogen. Laboratories normally report the Gross SE of the coal. The Net SE can be calculated using the following formula:-

$$SE_{net} \ = \ SE_{gross} \ - \ 2.42 \left(\frac{H_2O}{100} \ + \ 9 \, \frac{H_2}{100} \right) \quad \text{(MJ/kg)} \tag{3.1}$$

> where: SE = Specific Energy (MJ/kg) as received)
> H_2O = Moisture Content (% as received)
> H_2 = Hydrogen Content (% as received)

The Gross SE can be calculated from the ultimate analysis of the coal using the Dulong formula. The results from this calculation are usually within 1.5% of the measured value for bituminous and anthracitic coals. The formula is:-

$$SE \ = \ 33.83C \ + \ 144.25 \left(H \ - \ \frac{O}{8} \right) \ + \ 9.42S \quad \text{(MJ/kg)} \tag{3.2}$$

where C, H, O and S = fractions of carbon, hydrogen, oxygen and sulphur.

Table 3.2 details a typical coal analysis for a bituminous coal.

Analysis		As Received (ar)	Air Dried Basis (adb)	Dry Basis (db)	Dry Ash Free (daf)
Proximate Analysis					
Moisture	%	10.0	2.5	–	–
Ash	%	9.2	10.0	10.3	–
Volatiles	%	27.7	30.0	30.8	34.3
Fixed Carbon	%	53.1	57.5	58.9	65.7
Ultimate Analysis					
Carbon	%	68.3	73.9	75.8	84.5
Hydrogen	%	4.6	5.0	5.1	5.7
Nitrogen	%	1.5	1.7	1.7	1.9
Sulphur	%	0.4	0.4	0.4	0.5
Oxygen (Diff.)	%	6.0	6.5	6.6	7.4
Specific Energy					
Coal	MJ/kg	28.1	30.4	31.2	34.7
	Kcal/kg	6,700	7,260	7,450	8,300
	BTU/lb	12,060	13,070	13,400	14,930

Table 3.2 – Analysis of a Typical Australian Coal
(Source: Juniper, 1999, p14)

There are numerous other qualities of coal that can be tested including ash fusion temperatures, grindability and abrasion indexes and trace element analysis. These qualities were not described in any detail in this project.

3.2   Boiler Plant Description

3.2.1   Introduction

The boilers used at Stanwell Power Station are a single drum radiant type manufactured by Babcock-Hitachi. At maximum continuous rating they evaporate 297.7 kilograms of water per second. The design pressure of the boiler is 19,890 kPa (gauge) and the main steam pressure and temperature are 17,569 kPa (gauge) and 541˚C respectively. The steam produced in the boiler is used to drive the high, intermediate and low pressure turbines at 3,000 rpm providing 350 MWe at full load. Figure 3.1 provides an example of a boiler similar in construction to the Stanwell boiler.
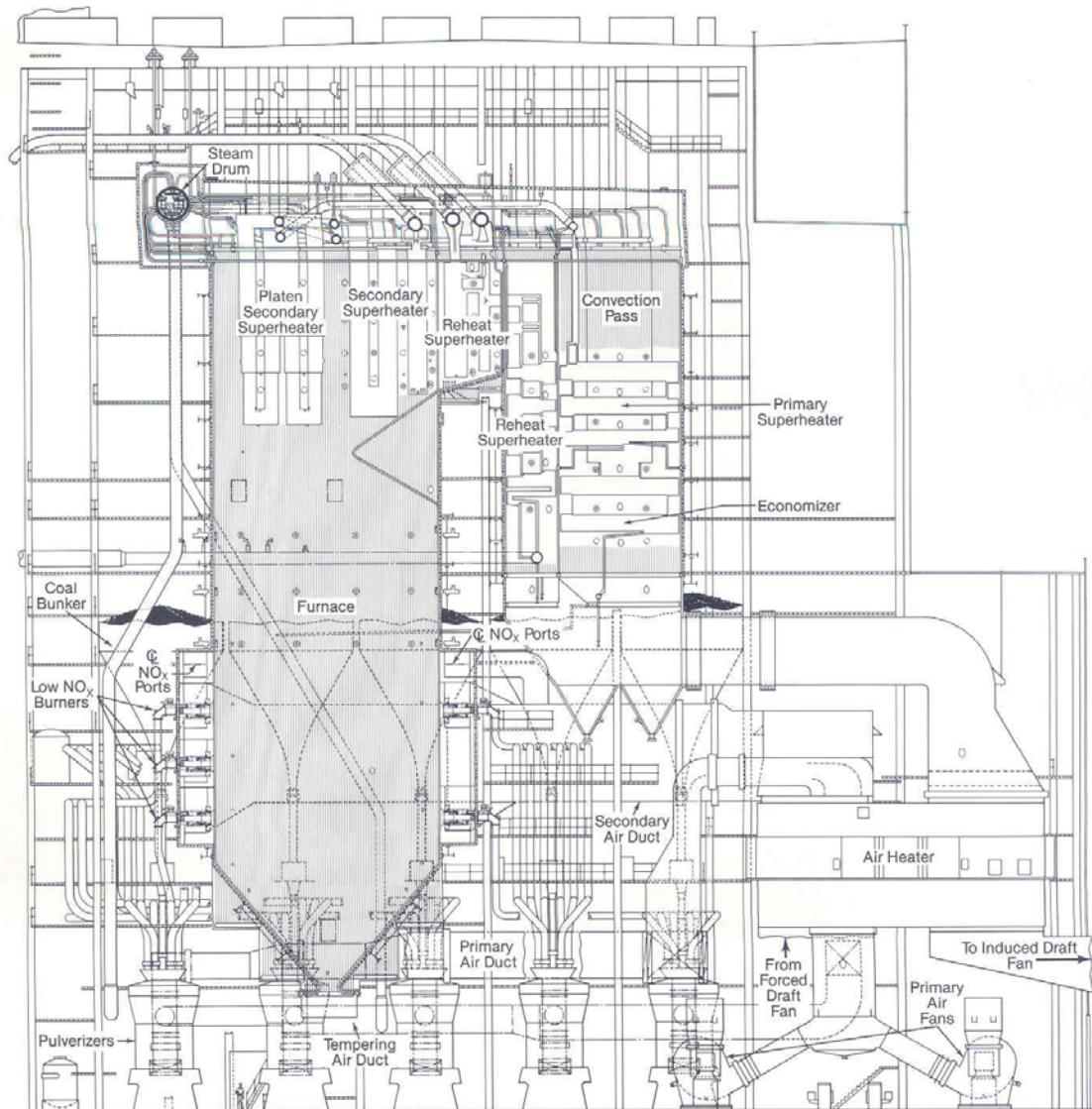
Figure 3.1 – General Boiler Arrangement
(Source: Babcock & Wilcox, 1992, p40)

3.2.2   Water and Steam Plant

The water/steam circuit comprises the following major items of plant:-

Economiser

The economiser section of the boiler comprises banks of horizontal finned tubes located in the rear pass of the boiler. Heat from the flue gases is transferred by convection to the feedwater passing through the tubes. The economiser is the last element of the boiler that extracts heat from the flue gas prior to the gas passing out of the boiler and through the air heaters. Feedwater is delivered to the economiser section by boiler feed pumps via a series of high pressure heaters. The economiser serves the purpose of heating the feedwater prior to delivery to the drum and as such results in less energy required to transform the feedwater to steam resulting in improved thermal efficiency.

Boiler Drum

The boiler drum is a large cylindrical vessel located at the top of the boiler. The major connections to the drum allow for:-

- Incoming feedwater from the economiser
- Incoming water-steam mixture from the boiler water walls and screen wall
- Incoming chemical dosing lines
- Outgoing downcomers which deliver water to headers located at the bottom of the boiler prior to entering the water walls
- Outgoing saturated steam to the superheaters

Figure 3.2 details a typical cross section of a boiler steam drum.
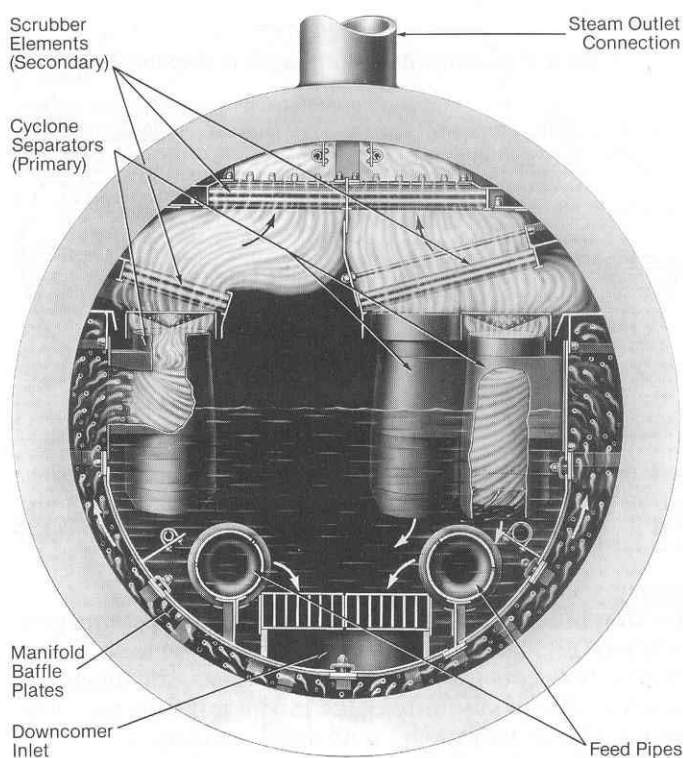
Figure 3.2 - Cross Section of Steam Drum
(Source: Babcock & Wilcox, 1992, p5-13)

The main function of the drum is to perform effective separation of the water and steam. Efficient separation is achieved by installing mechanical devices such as cyclone separators and scrubbers. Separation of the water-steam mixture is critical in most boiler applications in order to:-

- Prevent thermal damage to the superheaters by water droplet carryover
- Minimise the amount of steam entrained in the water entering the downcomers thus reducing the effective hydraulic pumping head of the circulation system
- Prevent solids dissolved in water droplets entrained in the steam from damaging the superheaters and turbine

The circulation of the water steam mixture in the Stanwell boiler is achieved through natural circulation. As Figure 3.3 shows, water containing no steam flows down the

unheated downcomers. As heat is added to the boiler tubes a water-steam mixture is formed that has a density lower than that of the water. By this mechanism gravity causes the denser water to force the water-steam mixture back into the drum. In other systems circulation may be achieved by the installation of circulation pumps (Babcock & Wilcox, 1992).
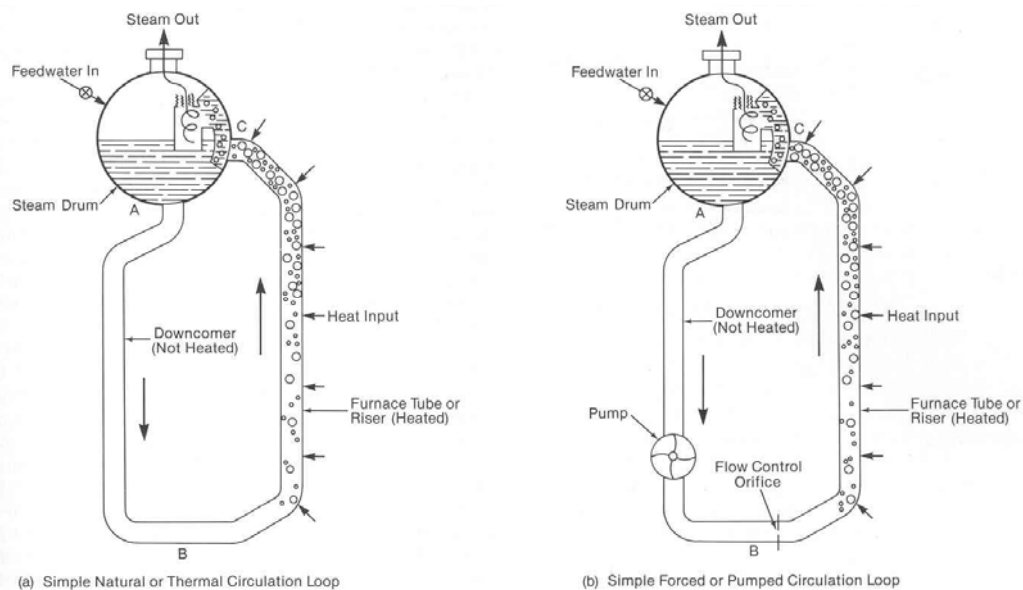
Figure 3.3 – Natural and Forced Circulation Systems
(Source: Babcock & Wilcox, 1992, p1-7)

Furnace Water Walls

The furnace water walls absorb the heat made available from the combustion of pulverised fuel. The dominant mode of combustion in this region is radiation. The front, rear and side water walls emerge from a series of headers located at the bottom of the boiler that are fed from the downcomers. Figure 3.4 shows how the water walls are formed around the burner area.

The water walls consist of panels of tubes joined by membrane bars spaced at close centres to maximise heat absorption as shown in Figure 3.5. The size of the furnace

and hence the projected area of the water wall tubes is determined so as to allow complete combustion of the fuel and also to allow enough heat to be absorbed from the flue gas so that the temperature of the flue gases entering the convection zone of the boiler is acceptable.
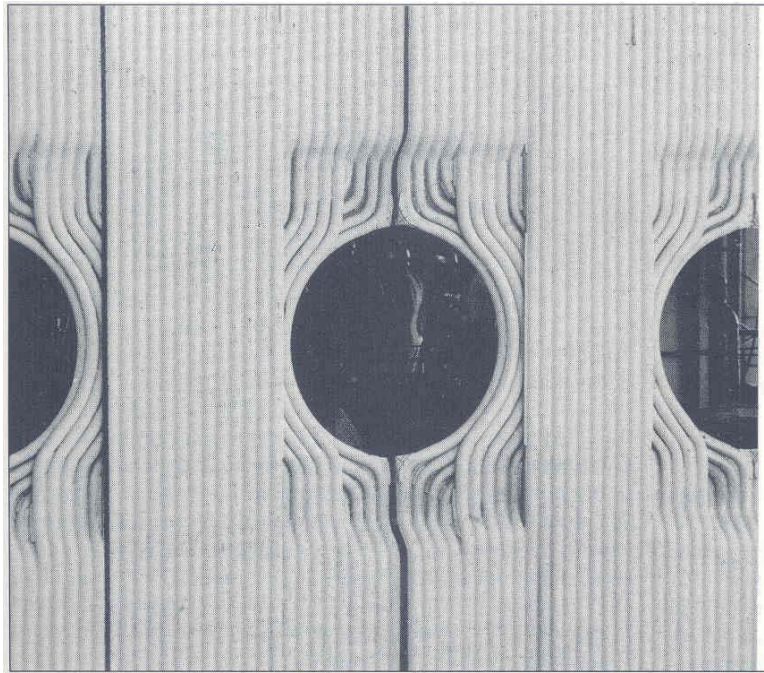
Figure 3.4 - Membrane Water Wall Construction showing Pulverised Fuel Burner Openings (Source: Babcock & Wilcox, 1992, p18-6)
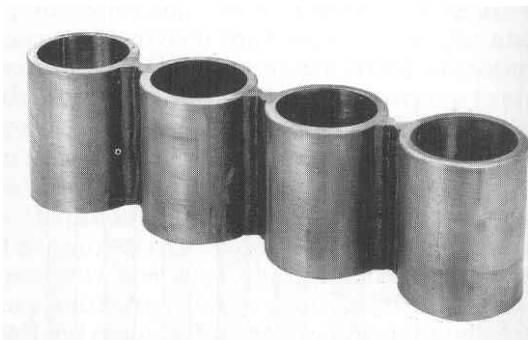
Figure 3.5 – Water Wall Tubes
(Source: Babcock & Wilcox, 1992, p18-6)

Superheaters

The superheaters are heat exchange devices of either pendant or bank type that increase the temperature of the saturated steam. Increasing the temperature of the steam at constant pressure improves the quality of the steam and permits its use in the high pressure turbine. It is important that enough superheat is added to the steam so that water droplets are not formed on the turbine blades resulting in damage to the blades.

Reheaters

Reheaters are similar in design to superheaters but differ in the fact that they operate at lower pressures (Babcock & Wilcox, 1992). Steam, still above the saturation line, flows from the high pressure turbine into the reheat system where superheat enthalpy is added to the steam prior to use in the intermediate and low pressure turbines.

3.2.3   Draught Plant

Forced Draught Fans

The forced draught fans supply air to the furnace for combustion of the pulverised coal. The fans are a constant speed axial type with variable pitch blades that control the amount of air delivered to the furnace. The fan blade pitch is governed by the amount of excess oxygen in the flue gas. As the excess oxygen level ranges above or below the required set point, the blade pitch is decreased or increased resulting in the required amount of air being available for combustion.

The air supplied from the forced draught fans, termed secondary air, passes through the air heater where it is heated to approximately 330ºC before passing through the windbox dampers and air registers and into the furnace.

Primary Air Fans

The primary air fans are centrifugal type fans that take air from the outlet of the forced draught fans and are used to supply air to the mills. After passing through the air heater the primary air is combined with unheated tempering air to dry the coal in the mills and transport the pulverised fuel to the furnace. The mixing of the hot primary air and the unheated tempering air is performed using dampers prior to entry to the mill. The position of these dampers is controlled to maintain a mill outlet temperature of 90ºC. The primary air carrying the pulverised fuel to the furnace generally accounts for 20% of the required combustion air.

Induced Draught Fans

The induced draught fans are a centrifugal style of fan that remove the combustion gases from the furnace. A variable inlet vane on the fan is used to control the furnace pressure to –0.2 kPa (gauge). This slight vacuum is maintained to prevent hot gases, unburnt fuel or ash escaping from the furnace. At full load the two (2) induced draught fans are capable of removing over 450 kg/s of waste gas.

Air Heaters

Rotary regenerative air heaters are used to heat the primary and secondary air before the air passes into the mills or furnace. Heat is extracted from the flue gases as they pass out from the boiler over banks of finned elements contained within the air heater. As the hood arrangement rotates, heat is transferred to the air passing over the heated fins. The gas inlet temperature to the air heaters is approximately 380°C. The heat transfer to the elements drops the temperature by around 244°C to 136ºC. Excess heat transfer needs to be avoided as damage to downstream equipment will result if the dew point is reached resulting in the formation of sulphuric acid.

3.2.4   Fuel and Combustion Plant

Feeders and Mills

Coal feeders deliver "As Received" coal from the coal bunkers to the pulverisers using a gravimetric weighing process. The mass of the coal on the coal feeder belt is determined using load cells. This measurement is multiplied by the belt speed to give a coal flow in kilograms per second. A 350 MW unit operating at full load typically operates with four mills in service, each mill grinding approximately 8.5 kilograms per second of coal.

Within the pulveriser, in this case a vertical spindle mill, the coal is crushed to a mass mean size of about 50 μm, roughly the diameter of a human hair, to ensure rapid combustion within the furnace. Essentially all of the particles are less than 300 μm. The size distribution follows the Rosin-Rammler distribution (Borman & Ragland, 1998) as depicted in Figure 3.6.
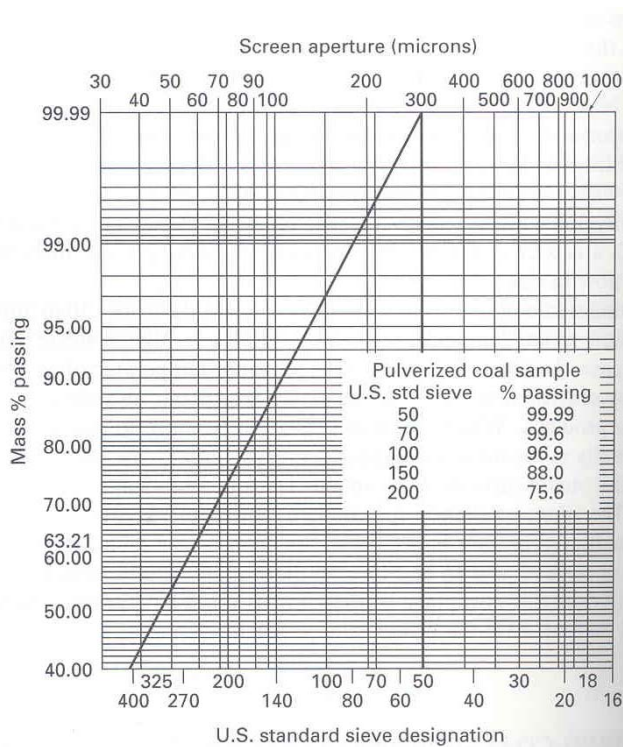
Figure 3.6 – Rosin-Rammler Chart for Pulverised Coal
(Source: Borman & Ragland, 1998, p508)

Burners and Windboxes

The combined fuel-primary air mixture is transported from the pulveriser, after passing through the classifying system, to the pulverised fuel burners. The velocity of the fuel-air mixture in the delivery pipes must exceed 15 m/s to avoid settling of pulverised fuel in any horizontal sections of pipe. At the burner nozzle the velocity of the fuel-air mixture must exceed the speed of flame propagation so as to avoid flashback. The flame speed is dependent on the fuel-air ratio, particle size distribution, tube diameter, air preheat, and volatile matter and ash in the coal. Figure 3.7 shows typical flame speeds for mixtures of sub-bituminous pulverised coal and air.
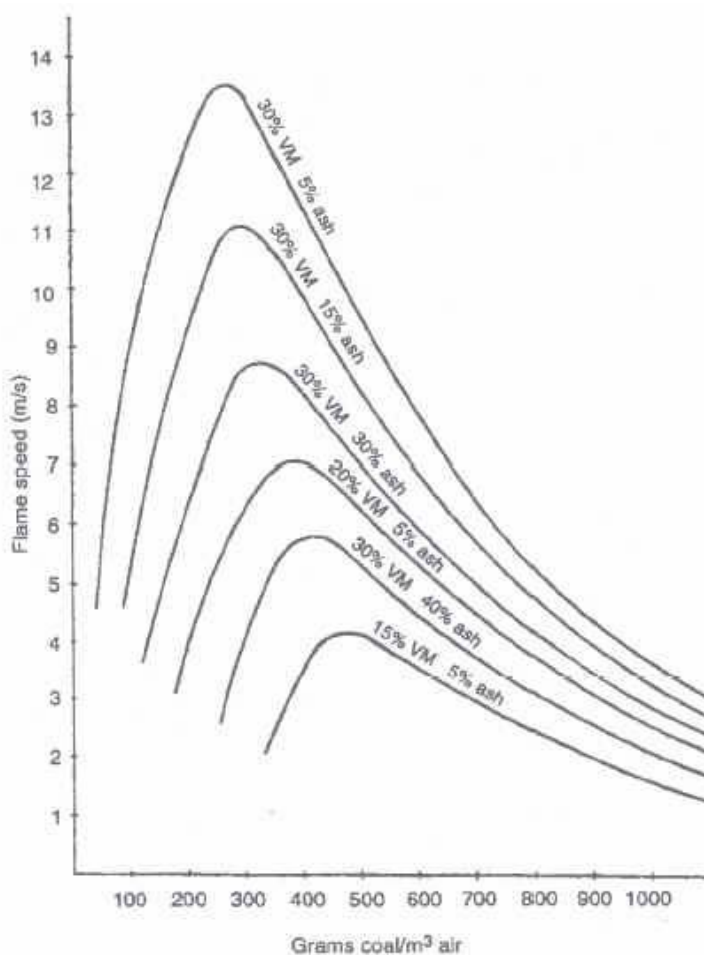
Figure 3.7 – Typical Flame Speeds for Sub-Bituminous Pulverised Coals and Air
(Source: Borman & Ragland, 1998, p510)

The burner also contains an oil gun which burns fuel oil and is used for first light in the furnace after an extended period out of service and also to assist in the ignition of the coal particles if the coal flame becomes unstable.

The secondary air supply provides the bulk of the air required for combustion and is delivered to the windboxes at a velocity of approximately 40 m/s and at a temperature of approximately 330°C. The secondary air is introduced to the furnace through the secondary air vanes of the air register, refer Figure 3.8, which impart a swirl on the air about the burner axis (Juniper, 2000).
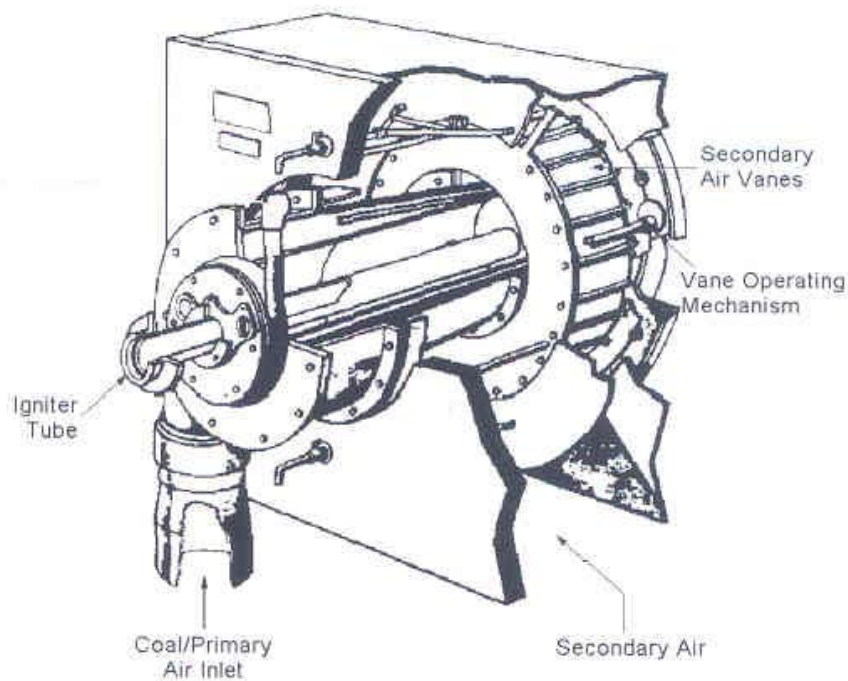
Figure 3.8 – Swirl Burner
(Source: Juniper, 2000, p61)

This technique has long been used to increase flame stability and the intensity of combustion and results in a shorter and wider flame. The increase in ignition stability is due to an axial recirculation vortex which carries burning gases back towards the

burner where they become entrained in the primary fluid prior to ignition. Figure 3.9 details the flow path of the combustion products in a typical burner.
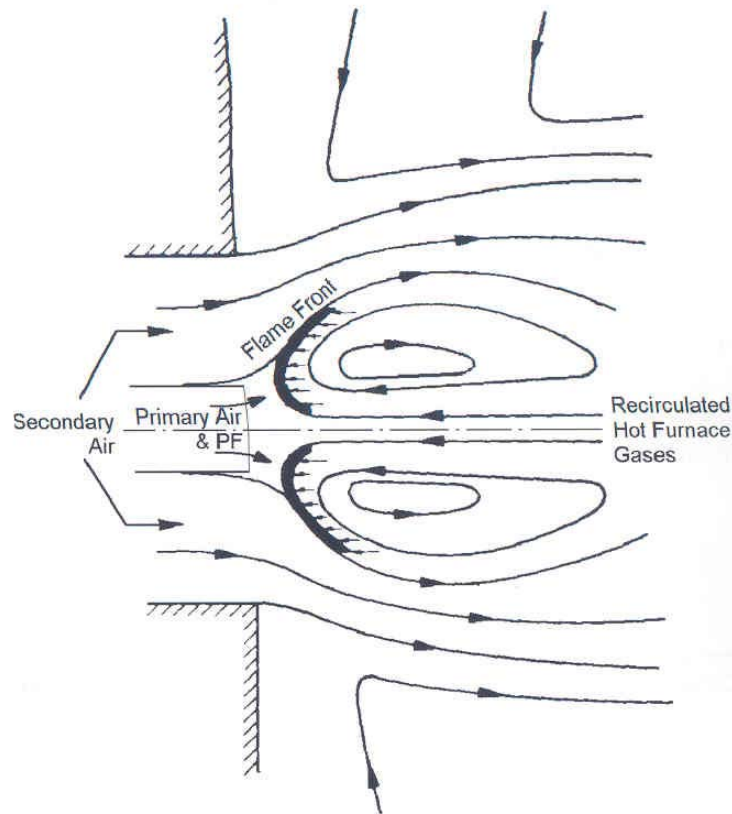
Figure 3.9 – Aerodynamic Flow Pattern in a Swirl Burner
(Source: Juniper, 2000, p62)

Coal Combustion Principles

4

4.1   Introduction

Borman and Ragland (1998) describe combustion as the rapid conversion of chemical energy to sensible energy. This process involves a transformation of reactants (fuels and oxidizers) to the products of combustion.   During the transformation there is no alteration of the nuclei of the reactants, however the creation or destruction of bonds involving the electrons of the molecules takes place. This process may cause heat to be liberated or heat may be required to form the bonds. When a chemical reaction liberates heat it is termed an exothermic reaction whereas where energy is absorbed, it is termed endothermic.

In the case of a pulverised fuel boiler, the energy derived from an exothermic reaction can be exploited and used in the generation of steam.

4.2   Pulverised Coal Combustion within a Furnace

Juniper (2000) describes the processes that occur when a coal particle is combusted in a pulverised fuel (PF) boiler as follows:-

- Release and combustion of volatile matter
- Combustion of the residual char
- Release of the mineral matter

When a 100μm coal particle passes through a burner nozzle into a 1,400°C flame zone the particle reaches 400°C in around one (1) ms and 1,000°C after approximately ten (10) ms.

At 100°C the moisture is drawn off and at 400°C devolatilisation begins. The gaseous volatiles contain various gases including CO_2, H_2O, N_2 and small proportions of CO, H_2, HCN and a variety of hydrocarbons (C_xH_y). These volatiles are mixed with the surrounding air and are rapidly burnt (Borman & Ragland, 1998).

By the time the particle reaches 1,000°C, devolatilisation is complete and porosity has been established in the char particle which consists of carbon, mineral matter and ash. At this stage oxygen reaches the char particle for the first time and char burning begins. Between ten (10) ms and 0.5s, half of the char is consumed with a surface temperature several hundred degrees hotter than the gas temperature due to surface reactions with the oxygen. As the reaction continues porosity increases and fissures are formed. The molten mineral matter begins to agglomerate and towards the latter parts of burnout the char may fragment into several pieces (Borman & Ragland, 1998). The process is depicted in Figure 4.1.
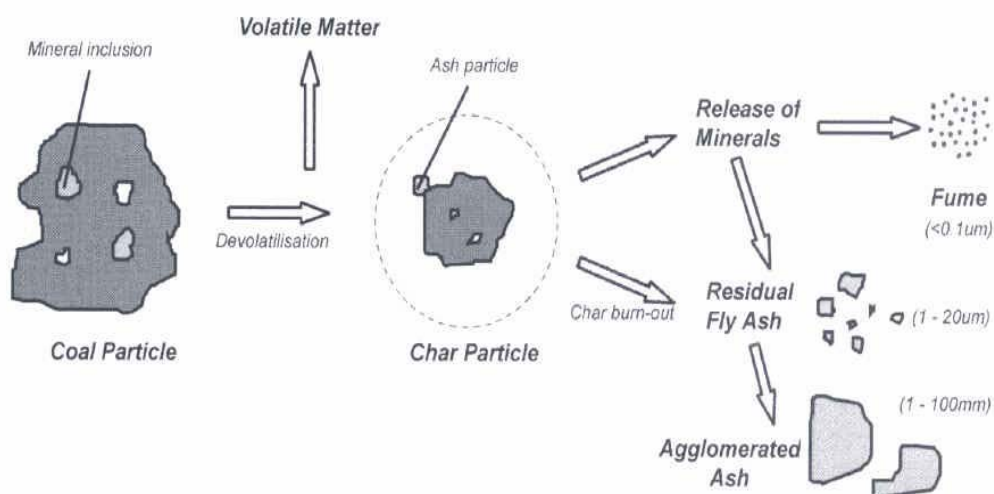
Figure 4.1 – Processes Occurring During Combustion
(Source: Juniper, 1999, p27)

4.3   Mole and Mass Fractions

Turns (2000) states that when dealing with combustion problems it is useful to be able to characterise the composition of a mixture by both the mass fraction and the mole fraction. The mole fraction of species i, χ_i is defined as the fraction of the total number of moles in the system that are species i; that is:-

$$\chi_i \equiv \frac{N_i}{N_1 + N_2 + ... + N_i + ...} = \frac{N_i}{N_{total}} \qquad (4.1)$$

where N_i is the number of moles of species i

The mass fraction of species i, Y_i, is the amount of mass of species i compared to the total mixture mass:-

$$Y_i \equiv \frac{m_i}{m_1 + m_2 + ... + m_i + ...} = \frac{m_i}{m_{total}} \qquad (4.2)$$

where m_i is the mass of the individual species i

The mole and mass fractions are easily converted from one to another using the molecular weights of the mixture and of the species of interest:-

$$Y_i = \frac{\chi_i MW_i}{MW_{mix}} \qquad (4.3)$$

$$\chi_i = \frac{Y_i MW_{mix}}{MW_i} \qquad (4.4)$$

The mixture molecular weight, MW_{mix} can be calculated from knowledge of either the species mass or mole fractions:-

$$MW_{mix} = \sum_i \chi_i MW_i \qquad (4.5)$$

$$MW_{mix} = \frac{1}{\sum_i \dfrac{Y_i}{MW_i}} \qquad (4.6)$$

Analysis		Air Dried Basis (adb)
Proximate Analysis		
Moisture	%	1.1
Ash	%	18.1
Volatiles	%	27.7
Fixed Carbon	%	53.1
Ultimate Analysis		
Carbon	%	71.3
Hydrogen	%	3.71
Nitrogen	%	1.4
Sulphur	%	0.54
Oxygen (Diff.)	%	3.85
Specific Energy		
Coal	MJ/kg	28.83

Table 4.1 Coal Analysis

Using the values from the analysis detailed in Table 4.1 and the atomic mass of the individual elements from the periodic table shown in Appendix C, the mixture molecular weight on an ash free basis can be determined using Equation 4.6 as follows:-

$$MW_{mix} = \frac{1}{\Sigma\left(\dfrac{Y_i}{MW_i}\right)}$$

$$= \frac{1}{\dfrac{0.713}{12.01} + \dfrac{0.0371}{2(1.008)} + \dfrac{0.014}{2(14.01)} + \dfrac{0.011}{2(1.008)+16} + \dfrac{0.0385}{2(16)} + \dfrac{0.054}{32.07}}$$

$$= 12.246$$

The mole fractions of the individual species can now be readily calculated and are shown as follows:-

$$\chi_{carbon} \quad = \quad 0.727$$

$$\chi_{nitrogen} \quad = \quad 0.006$$

$$\chi_{H_2O} \quad = \quad 0.007$$

$$\chi_{oxygen} \quad = \quad 0.014$$

$$\chi_{sulphur} \quad = \quad 0.021$$

$$\chi_{hydrogen} \quad = \quad 0.225$$

By definition, the sum of the constituent mole or mass fractions must be unity, ie.,

$$\sum_i \chi_i \quad = \quad 1 \tag{4.7}$$

$$\sum_i \gamma_i \quad = \quad 1 \tag{4.8}$$

This can be verified by summing the mole fractions detailed above.

4.4   Stoichiometry Requirements

Turns (2000) describes the stoichiometric quantity of an oxidiser (O_2) as being the exact amount required to completely burn a quantity of fuel. If less than the stoichiometric amount of oxidiser is supplied, the mixture is said to be fuel rich while if greater than the required amount of oxidiser is supplied, the mixture is termed fuel lean. Pulverised fuel boilers in general run on a fuel lean mixture. This is done not only to extract the maximum energy from the fuel through the

minimisation of carbon losses but also combustibles passing out of the furnace create an increased risk of fire and explosion risks in the rear pass of the boiler.

4.5   Simple Atom Balance

The stoichiometric quantity of O_2 is determined by writing simple atom balances and assuming that all carbon converts to CO_2, all hydrogen converts to H_2O, and all sulphur converts to SO_2. The inherent oxygen in the coal contributes to the required O_2 and is consumed as part of the above reactions. It is assumed there is no dissociation of species and all other constituents namely ash, nitrogen, moisture and trace metals take no part in the combustion process. This is shown as:-

$$C + O_2 \;\rightarrow\; CO_2 \tag{4.9}$$

$$H_2 + \frac{1}{2}O_2 \;\rightarrow\; H_2O \tag{4.10}$$

$$S + O_2 \;\rightarrow\; SO_2 \tag{4.11}$$

For stoichiometric combustion one (1) mole of carbon with a mass of 12.01 grams requires one (1) mole of diatomic oxygen with a mass of 32 grams. Dividing through by the mass of the carbon results in a fuel-oxidiser ratio on a mass basis of 1:2.67. Similarly the stoichiometric combustion requirement for the other reactants present in the coal can be determined on a mass basis and are summarised below:-

Reactant	O_2 Requirement
1 kg carbon	2.67 kg
1 kg hydrogen	7.94 kg
1 kg sulphur	1.00 kg

Therefore the oxygen requirements for stoichiometric combustion for one kilogram of coal as described in Table 4.1 can be determined as follows:-

0.7130 kg	carbon	requires	1.9040 kg of oxygen
0.0371 kg	hydrogen	requires	0.2950 kg of oxygen
0.0054 kg	sulphur	requires	0.0054 kg of oxygen
0.0385 kg	oxygen	consumed in process	- 0.0385 kg of oxygen
		TOTAL	2.1660 kg of oxygen

Summing the required amount of oxygen and subtracting the inherent oxygen results in a requirement of 2.166 kg of oxygen for every kilogram of coal. The atmospheric air used in the combustion process is 23.2% by mass oxygen, the majority of the remainder of this mixture being inert nitrogen. Therefore the stoichiometric air requirement is determined as:-

$$Stoichiometric\ Air\ = \frac{2.166}{0.232}$$

$$= 9.33\,kg$$

4.6   Equivalence Ratio

The equivalence ratio, Φ, is used to indicate quantitatively whether a fuel-oxidiser mixture is lean, rich, or stoichiometric. It is defined as:-

$$\Phi = \frac{(A/F)_{stoic}}{(A/F)} = \frac{(F/A)}{(F/A)_{stoic}} \qquad\qquad (4.12)$$

where A/F is the mass air-fuel ratio (kg/kg)

The definition is such that for stoichiometric mixtures, $\Phi = 1$, for fuel rich mixtures, $\Phi > 1$, and for fuel lean mixtures, $\Phi < 1$.

The mass flow rate of coal with the boiler operating at 270 MW is approximately

26 kg/s. The bulk of the combustion air is provided to the furnace by the forced draught fans with a small amount of air provided via the Sealing Air System on the mills and coal feeders. For the given fuel rate the required combustion air is 26 (2.166) = 242.6 kg/s. Due to an imperfect sealing arrangement in the rotating regeneratitive air heaters, combustion air is lost from the higher pressure air side to the lower pressure gas side of the air heater before reaching the furnace. Recent testing indicated this efficiency loss to be approximately 5% resulting in a requirement of 1.05 (242.6) = 254.7 kg/s of combustion air.

Using air flow values taken from the boiler control system for the forced draught system and values from the performance curve for the seal air fan show mass flow rates of air of 298 kg/s and 3.87 kg/s respectively. The equivalence ratio, Φ, for this particular configuration is determined as follows:-

$$\dot{m}_{coal} = 26 \ {kg}/{s}$$

$$\dot{m}_{inherent\ oxygen} = 26 \ (0.0385)$$

$$= 1 \ {kg}/{s}$$

$$\dot{m}_{forced\ draught} = 298 \ {kg}/{s}$$

$$\dot{m}_{seal\ air} = 3.87 \ {kg}/{s}$$

$$\dot{m}_{air\ heater\ loss} = 0.05 \ (298)$$

$$= 14.9 \ {kg}/{s}$$

$$\overset{\bullet}{m}_{combustion\,air} = 298 + 3.87 - 1 - 14.9$$

$$= 286 \; {kg}/{s}$$

Using Equation 4.12 the equivalence ratio is determined as:-

$$\Phi = \frac{\left(\dfrac{9.33}{1}\right)}{\left(\dfrac{286}{26}\right)}$$

$$= 0.85$$

With the equivalence ratio now determined the percentage value of excess air can easily be evaluated using the following:-

$$\% \, Excess\, Air = \frac{1 - \Phi}{\Phi} \, 100 \; \%$$

(4.13)

$$= 20.5 \; \%$$

This amount of excess air will contain approximately 4.8% oxygen. This relates closely to the amount of excess oxygen measured by the O_2 analysers located at the boiler exit under normal operation.

No$_x$ Creation Mechanisms and Control

5

5.1   Introduction

Nitrogen oxide (NO) and nitrogen dioxide (NO$_2$) known collectively as NO$_x$ are atmospheric pollutants that contribute to the production of photochemical smog and acid rain. NO$_x$ formation occurs during combustion in utility boilers regardless of the fuel being used. However, of the three major fuels (coal, oil and gas), coal is the most significant producer of NO$_x$ due to the nitrogen contained in the fuel itself.

The Electric Power Research Institute (EPRI) (1993) describe the production of NO$_x$ formation in coal fired boilers by two dominant mechanisms, thermal NO$_x$ and fuel NO$_x$. Thermal NO$_x$ results from the oxidation of nitrogen present in the combustion air, and fuel NO$_x$ results from the oxidation of nitrogen organically bound in the fuel. Figure 5.1 shows the relative contribution of thermal and fuel NO$_x$ to total NO$_x$ created using a high volatile bituminous coal for a range of stoichiometric ratios.
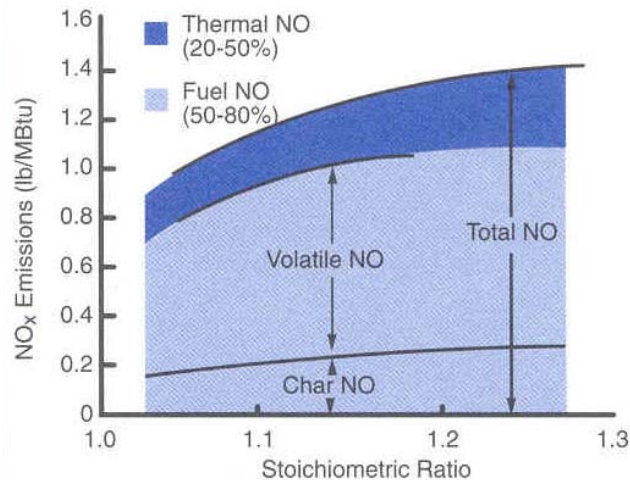
Figure 5.1 - Relative Contribution of Fuel NO and Thermal NO to Total NO$_x$ Emissions (Source: Electric Power Research Institute, 1993, p3-2)

A third mechanism, the prompt or Fenimore mechanism, results in the formation of NO$_x$ as a result of the reaction of nitrogen with partially burned hydrocarbons. A

significant fraction of the NO$_x$ produced in this way is converted to diatomic nitrogen in the boiler and as such was not considered further.

5.2   NO$_x$ Creation Mechanisms

5.2.1   Fuel NO$_x$

Fuel NO$_x$ generally accounts for between 50% to 80% of the total NO$_x$ formed during conventional pulverised coal burning. Fuel NO$_x$ is formed by the oxidation of the nitrogen present in the fuel during the devolatilisation and char burnout stages of combustion. Reactive gas phase nitrogen species develop from the nitrogen bound within the coal as the volatile matter evolves during combustion. High flame temperatures and high oxygen availability during devolatilisation encourage the conversion of volatile released nitrogen to NO$_x$. The rates of NO$_x$ production from the char bound nitrogen are lower primarily due to the lower availability of oxygen in this stage of combustion (Babcock and Wilcox, 1992).   Figure 5.2 details the conceptual diagram of fuel bound nitrogen evolving to NO$_x$.
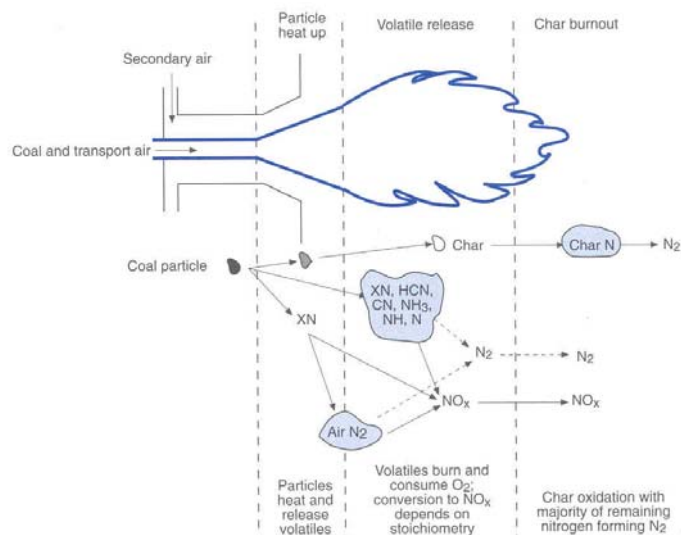
Figure 5.2 - Conceptual Diagram of Fuel Bound Nitrogen to NO$_x$
(Source: Electric Power Research Institute, 1993, p3-3)

The most effective method of reducing the amount of fuel NO_x during combustion is to limit the amount of oxygen available as the volatiles are released. Air required to complete the char reaction process can be introduced later in the process to ensure sufficient burnout of the char particle and maintain combustion efficiency.

The availability of oxygen during devolatilisation can be reduced by two methods. One method is to introduce combustion air elsewhere in the furnace and the second method is the modification or replacement of existing burners so that the rate at which air is introduced to the flame is reduced. Both of these staging techniques are described in greater detail later in this chapter.

5.2.2   Thermal NO$_x$

The products of high temperature combustion are not as simple as those described by the simple atom balances used to determine stoichiometry. Rather the major species dissociate which results in the production of a host of minor species including O, N, OH, H, CH, HCN, N_2O and NO. Thermal NO_x is formed from the dissociation and oxidation of the nitrogen admitted to the furnace with the combustion air (Turns, 2000).

The rate at which thermal NO_x can be formed is dependent upon the availability of oxygen in the flame and post flame zone and is exponentially dependent upon the temperature resulting from combustion. The reactions for thermal NO_x formation occur rapidly as combustion temperatures exceed 1,538ºC. Thermal NO generally accounts for 20% - 50% of total NO_x.

The mechanism through which thermal NO_x is produced is well described by the six (6) reactions of the extended Zeldovich mechanism as shown in Equations 5.1, 5.2 and 5.3:-

$$O + N_2 \Leftrightarrow NO + N \tag{5.1}$$

$$N + O_2 \Leftrightarrow NO + O \tag{5.2}$$

$$N + OH \Leftrightarrow NO + H \tag{5.3}$$

The contribution to total thermal NO$_x$ of the third reaction pair is small for lean mixtures as is the case within the furnace. The first forward reaction controls the system but as this reaction has a very high activation energy it is slow at low temperatures. As a result thermal NO$_x$ is formed in the postflame products (Borman & Ragland, 1998).

The rate coefficients for the forward and reverse reactions with the temperature in Kelvin and units of m³/ kmol-s are:-

$$k_{+1} = 1.8 \times 10^{11} \exp(-38{,}370/T)$$

$$k_{-1} = 3.8 \times 10^{10} \exp(-425/T)$$

$$k_{+2} = 1.8 \times 10^{7} \, T \exp(-4680/T)$$

$$k_{-2} = 3.8 \times 10^{6} \, T \exp(-20{,}820/T)$$

$$k_{+3} = 7.1 \times 10^{10} \exp(-450/T)$$

$$k_{-3} = 1.7 \times 10^{11} \exp(-24{,}560/T)$$

Calculations reveal that the rate of formation of thermal NO is highly dependent on temperature, time and stoichiometry (Borman & Ragland, 1998).

5.3   NOx Control

There are numerous technologies available to reduce the NO$_x$ emissions produced in large coal fired boilers. These methods range significantly in cost, effectiveness, complexity and extent of modifications required to achieve the reduction. As greater than half of the total NO$_x$ produced will be fuel NO$_x$ the most effective measures concentrate on limiting the formation of fuel NO$_x$.

NO$_x$ control techniques presently available for use in utility boilers include:-

- Combustion optimisation
- Overfire air (OFA)
- Advanced low NO$_x$ burners
- Flue gas recirculation
- Reburning (natural gas, coal, fuel oil)
- Selective non catalytic reduction (SNCR), and
- Selective catalytic reduction (SCR)

Each of these methods is discussed in detail below.

5.3.1   Combustion Optimisation

The optimisation of existing combustion systems is a low cost technique to reduce NO$_x$ emissions at minimal cost. Where a unit is only slightly exceeding acceptable levels of emissions, the tuning of the boiler may reduce these levels enough to eliminate the need for any retrofit controls. Under certain circumstances reductions in NO$_x$ of up to 25% are achievable with correct combustion tuning however the typical value of reductions is less than 10%, with this figure likely to be inconsistent with load variations.

The implementation of advanced process control systems based on neural networks can be configured to reduce NO$_x$ emissions whilst maintaining efficiency over changing plant conditions and time.

5.3.2   Overfire Air (OFA)

Overfire air is a furnace air staging NO$_x$ reduction technique. A proportion of the combustion air supply is injected into the furnace above the area of most intense combustion, the burner zone, through specially installed OFA ports.

The injection of the balance of the combustion air above the fireball region allows the burn-out of the fuel to take place in a less intense, lower temperature combustion zone thus impacting both fuel NO$_x$ and thermal NO$_x$.

The use of overfire air has been applied in the power industry for over 25 years and is one of the most established NO$_x$ reduction technologies available (Canning, Jones & Balmbridge, 1999) . Figure 5.3 illustrates a typical overfire air layout.
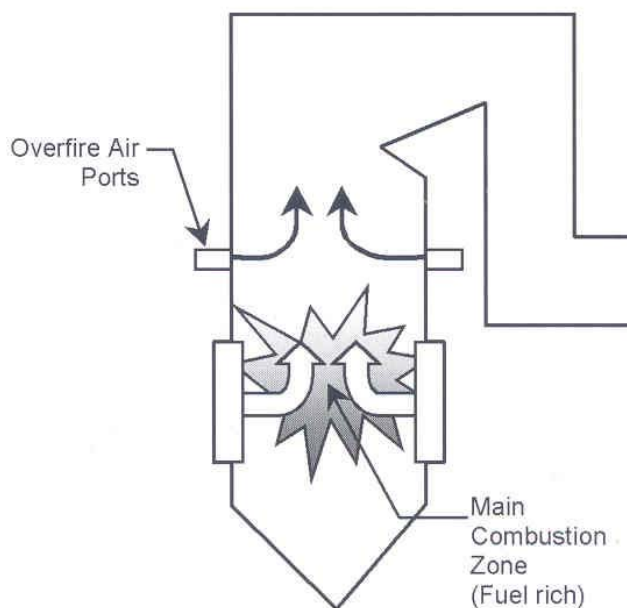
Figure 5.3 - NO$_x$ Reduction by Overfire Air
(Source: Juniper, 2000, p68)

5.3.3   Advanced Low NO$_x$ Burners (ALNB)

The original low NO$_x$ burners achieved reductions in NO$_x$ levels of up to 30% at the expense of boiler efficiency by way of carbon losses. It is now recognised that modern equipment can achieve an improved trade-off between NO$_x$ emissions and boiler efficiency (Canning et al, 1999).

The formation of NO$_x$ is reduced in low NO$_x$ burners by controlling the mixing of the air in the primary stages of the combustion process. The burners are designed such that a fuel rich primary zone of combustion is established in which organically bound nitrogen is reduced to molecular nitrogen. The balance of the combustion air then combines with the partial combustion products at a point further away from the burner throat. A reduction in peak flame temperature also ensues leading to a reduction in thermal NO$_x$ (Canning et al, 1999) .

The use of low NO$_x$ burners is likely to result in increased levels of unburnt carbon thus decreasing efficiency and may also impact on the saleability of the ash produced, as concrete manufacturers are unable to utilise fly ash with an excess of 5% unburnt carbon. Figure 5.4 details a low NO$_x$ burner arrangement.
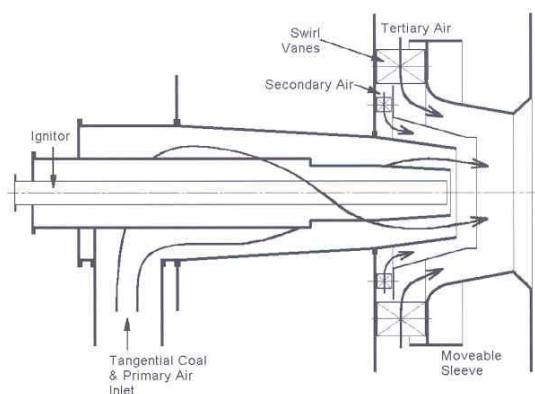
Figure 5.4 - Low NO$_x$ Burner
(Source: Juniper, 2000, p69)

5.3.4   Flue Gas Recirculation

Flue gas recirculation has been used to control the formation of NO$_x$ in gas and oil fired boilers. Combustion products may be taken from an area in the rear pass of the boiler, for example near the economiser and injected into the combustion air supply to the burners. It is believed that the primary NO$_x$ reduction mechanism is the reduction of peak flame temperature and gas residence times. Because the main effect of flue gas recirculation is on thermal NO$_x$ with minimal impact on fuel NO$_{x,}$ it is rarely considered as an option for NO$_x$ reduction in large coal fired boilers (Canning et al, 1999).

5.3.5   Reburning

Reburning technology is based on the principle that in regions of high temperature and low oxygen, hydrocarbon based radicals strip oxygen from NO molecules, with the remaining nitrogen ions combining to form molecular nitrogen.

Reburning is achieved by injecting a hydrocarbon based fuel above the main burners and combustion area. This fuel contributes to the thermal output from the boiler and produces a low stoichiometry NO$_x$ reduction zone. The balance of the combustion air to the furnace is injected via overfire air ports located above the reburn fuel injectors providing the oxygen required to burn out the reburn products and achieve the desired excess oxygen level for the system (Electric Power Research Institute, 1993).

A reburn system requires a sufficient separation between the main burner zone and the reburn zone to allow a satisfactory level of combustion of the main combustion products. Any unburnt char entering the reburn zone will not have yet released all of its nitrogen resulting in the likelihood of the nitrogen being oxidised to NO$_x$ in the reburn zone. The residence time in the burnout zone needs to be sufficient to ensure NO$_x$ destruction levels are achieved as well as the satisfactory burnout of the reburned fuel and carbon char from the main burner zone.

The effectiveness of a retrofit reburn facility is governed by furnace geometry. The relatively large plan areas of utility boilers can make satisfactory mixing of the initial combustion products with the reburn products very difficult. An inert carrying medium such as recirculated flue gas may be used to achieve satisfactory penetration of the reburn fuel across the furnace.
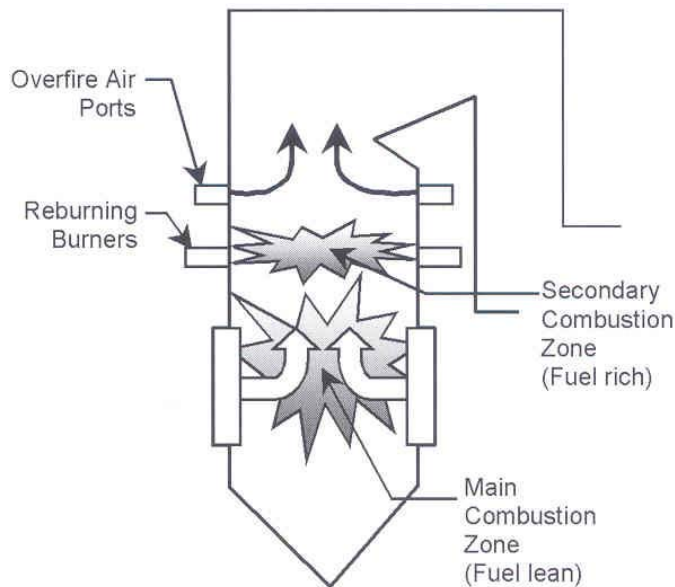
Figure 5.5 - NO$_X$ Reduction by Reburning

(Source: Juniper, 2000, p69)

5.3.6   Selective Non Catalytic Reduction

The selective non catalytic reduction process removes NO$_x$ by injecting a nitrogen based chemical reagent into the flue gas stream. The reagent, commonly urea or ammonia, combines with the NO$_x$ in the presence of oxygen to form oxygen and water vapour.

Difficulties in using selective non catalytic reduction arise as a result of a relatively narrow temperature window, in the range of 850°C – 1,050°C, necessary for the

desired chemical reactions to occur. If the reagent is injected into a region where the temperature is too low the process reduction rates decrease, resulting in increased amounts of ammonia (slip) passing out in the flue gas stream. If the reagent is injected into a zone where the temperature is too high the reagent begins to react with O_2 to actually form NO_x rather than reacting with the NO_x already present (Electric Power Research Institute, 1993).

The application of selective non catalytic reduction has proven to be difficult in large boilers as there are often high levels of gas stratification and uneven temperature distributions. There may also be problems with the contamination of saleable ash, the blockage of air heater baskets and environmental trade offs between NO_x emissions and process by-product emissions associated with ammonia slip (Canning et al, 1999).

5.3.7   Selective Catalytic Reduction

The selective catalytic reduction system removes NO_x from the flue gas stream by combining ammonia with the flue gas NO_x in approximately equimolar quantities. This mixture is then passed over a suitable catalyst material producing primarily nitrogen, water vapour and trace concentrations of ammonia and sulphur trioxide (Canning et al, 1999). The temperature under which the NO_x reducing reactions can occur is lowered to around 300°C - 400°C, typically the range of temperatures encountered in the economiser cross-over area prior to entry into the air heaters.

The installation of a selective catalytic reduction system typically involves the re-routing of the flue gas from the bottom of the economiser through the catalytic reactors before returning to the top of the air heaters. Problems that may arise due to the installation of selective catalytic reduction systems include contamination of saleable ash, air heater basket blockage and increased corrosion of downstream equipment due to high SO_3 concentrations and sulphuric acid mists. There are also the environmental considerations including the emissions of SO_3 and ammonia as well as the disposal of the potentially hazardous spent catalyst (Electric Power Research Institute, 1993).

Engineering Models

6

6.1   Introduction

A number of engineering models were developed to describe in sufficient detail the processes occurring within the boiler that are of interest to this project. Models were developed to estimate the residence time of the furnace, the initial flame temperature, the furnace heat pickup and the amount of thermal NO_x created.

6.2   An Engineering Model for Furnace Residence Times

6.2.1   Plug Flow

The time taken for an element to pass through the furnace is dependent on the particle path and flow patterns within the furnace. Only under perfect plug flow conditions where there is no mixing in the longitudinal direction can the residence time be known with certainty. In the case of plug flow, the residence time is the same for all material (Field, Gill, Morgan & Hawksley, 1967).

If $f(t)dt$ expresses the probability that material entering a combustor will reside there for a period t to $t + dt$, the fraction of feed residing for a period less than t may be written $F(t)$ where

$$F(t) = \int_0^t f(t)dt \qquad (6.1)$$

and the mean period of residence $\bar{t}$ may be determined as,

$$\bar{t} = \int_0^\infty tf(t)dt \qquad (6.2)$$

It is usual to express a residence time distribution in a plot of *F(t)* against $t/\bar{t}$ where

$t/\bar{t}$ is the ratio of time spent within the combustor to the average residence time. The

case for plug flow is illustrated in Figure 6.1.
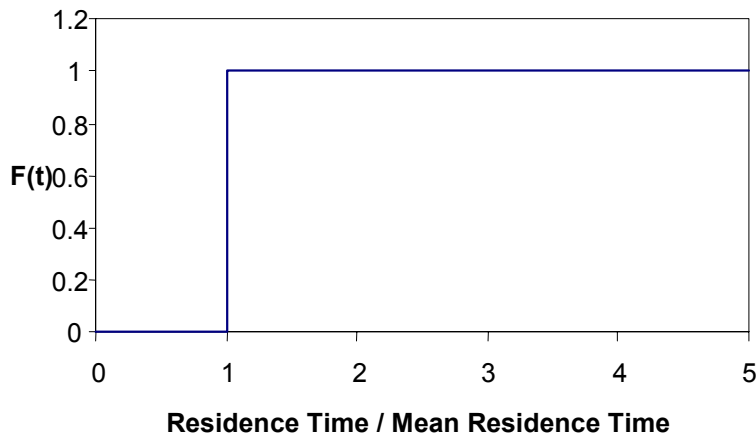
Figure 6.1 – Plug Flow

In reality, there will be significant mixing, recirculation zones, variations in boiler

inflow and boiler conditions which will result in variations in residence times

depending on the extent of departure from plug flow. As a consequence, a

combustor that has continual feed will have an exhaust which comprises a mixture of

different ages. Figure 6.2 illustrates plug flow modified by a degree of mixing.
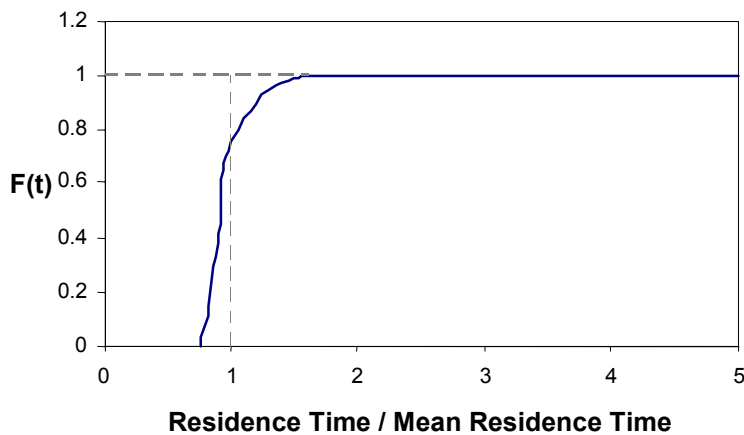
Figure 6.2 – Plug Flow with a Degree of Mixing

6.2.2   Residence Time Estimate for Stanwell Furnace

The residence time estimation for the Stanwell furnace was based on modified plug flow assuming that:-

1.   No fuel resides in the furnace less than 0.4 times the calculated mean residence time;

2.   That 90% of the combustion products have emerged 1.5 times the calculated mean residence time; and

3.   That no fuel resides in the combustion chamber for greater than 2.5 times the calculated mean residence time (Field et al, 1967).

Using this information an estimate for residence time can be developed as shown in Figure 6.3.
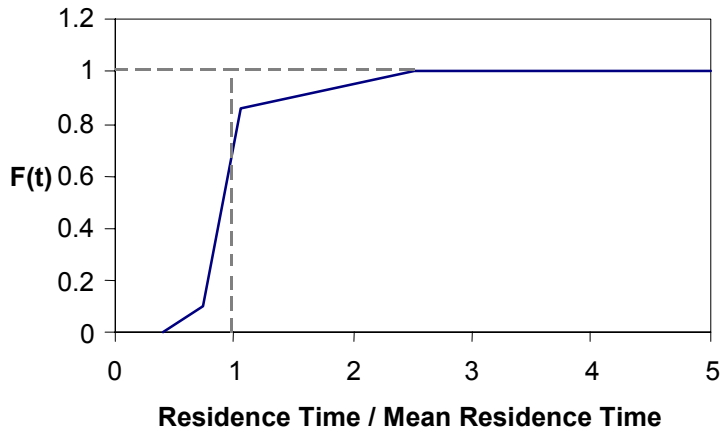
Figure 6.3 – Residence Time Estimate for Stanwell Furnace

Assuming an instantaneous conversion of the reactants detailed in Table 3.2 to combustion products, and an estimate of the average furnace temperature, the average residence time, $\bar{t}$, can be determined by calculating the density of the combustion product mixture, the volume of the combustion chamber and the mass flow rate of the reactants as follows:-

$$\rho = \frac{PMW_{mix}}{R_u T} \tag{6.3}$$

$$= \frac{101125(12.246)}{8314.3(1100+273)}$$

$$= 0.108 \ \frac{kg}{m^3}$$

> where: P = absolute pressure (Pa)
> MW_{mix} = molecular weight of the mixture (kmol/kg)
> R_u = universal gas constant (J/kg.K)
> T = temperature of combustion products (K)

Knowing the chamber volume and taking the mass flow rate of air and fuel from boiler control system data the residence time is determined as:-

$$\bar{t} = \frac{\rho V}{\overset{\bullet}{m}}$$
(6.4)

$$= \frac{0.108(4945)}{327}$$

$$= 1.63 \ \sec onds$$

$$where \ \overset{\bullet}{m} = mass \ flow \ rat \ (kg/s)$$
$$V = volume \ of \ combustion \ chamber \ (m^\wedge 3)$$

Applying the average residence time to the residence time estimate described above results in a minimum residence time of 0.65 seconds and a maximum residence time of 4.08 seconds.

6.3   An Engineering Model for Flame Temperature

The theoretical flame temperature is determined using a method described in Field et al (1967). The method is applicable to bituminous coal with moisture contents up to 20%, equivalence ratios of 0.8 to 1.5, and pressures of one (1), three (3), or ten (10) atmosphere. This satisfies the coal type and moisture content of the coals used at Stanwell and the furnace with a steady pressure of -0.2 kPa (gauge) can be assumed to be at one (1) atmosphere.

The method involves calculating the enthalpy of the products by combining the enthalpy of formation of the coal and the enthalpy of preheat and subtracting the heat losses from the flame. The amount of heat loss cannot be easily determined and for the purpose of this project will be assumed to be 15%. The value of the flame temperature is then calculated using the carbon/oxygen ratio, the nitrogen/oxygen

ratio and the calculated enthalpy with a correction made for the amount of nitrogen present in the flame zone.

The Matlab functions Flame_Temp.m and Flame_Splines.m have been developed to calculate the flame temperatures under varying conditions. Inputs to the function include percentages of carbon, hydrogen, oxygen, nitrogen and sulphur of dry ash free coal, the moisture content of air dried coal, total fuel and air flow. Linear and spline interpolation was used in the program to determine the values from a series of given graphs. The Matlab functions Flame_Temp.m and Flame_Splines.m are presented in Appendix B.

6.4   An Engineering Model for Furnace Heat Pickup

The processes that occur as heat is transferred from the combustion products within the furnace to the water walls enclosing the furnace is governed by the conservation of energy which states that there is a balance between the energy, work and heat quantities entering and leaving the system. The conservation of energy may be written:-

$$\begin{matrix} \text{Initial energy} \\ \text{of the system} \end{matrix} + \begin{matrix} \text{Energy entering} \\ \text{the system} \end{matrix} = \begin{matrix} \text{Final energy} \\ \text{of the system} \end{matrix} + \begin{matrix} \text{Energy leaving} \\ \text{the system} \end{matrix}$$

A system boundary can be applied such that the heat transfer to the water walls is a two flow open system. As there is an equal mass of fluid entering and leaving the system at any one time the system can be considered steady state. Figure 6.4 portrays such a system with the inlet boundary being the feedwater in and the outlet boundary being the steam out. These system boundaries can be used to determine the majority of the heat transferred to the water walls in the furnace region.
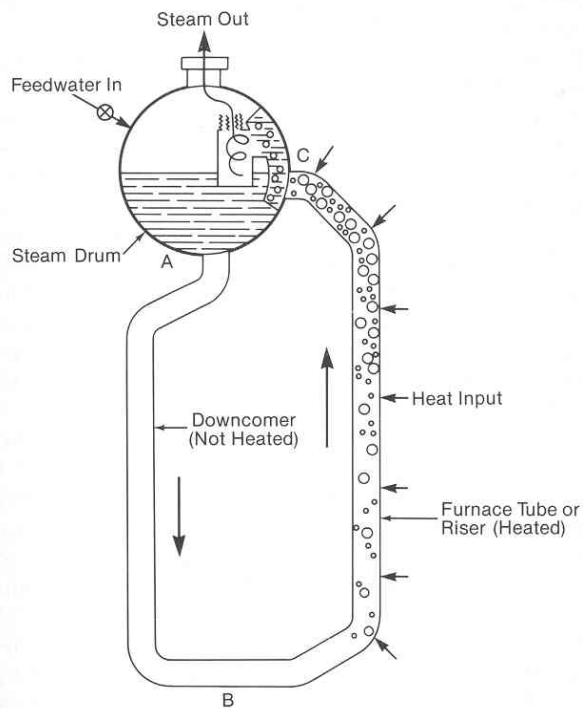
Figure 6.4 – Furnace Heat Pickup System
(Source: Babcock & Wilcox, 1992, p1-7)

The energy components associated with the moving fluid entering the system comprise the following:-

$$Internal\, Energy\; =\; U_1$$

$$Flow\, Energy\; =\; P_1 V_1$$

$$Kinetic\, Energy\; =\; KE_1$$

$$Gravitational\, Potential\, Energy\; =\; PE_1$$

whilst the energy components associated with the moving fluid leaving the system comprise:-

$$Internal\ Energy\ =\ U_2$$

$$Flow\ Energy\ =\ P_2V_2$$

$$Kinetic\ Energy\ =\ KE_2$$

$$Gravitational\ Potential\ Energy\ =\ PE_2$$

By convention the heat, Q, is positive if received by the system and negative if rejected by the system. External work, W, done by the system is positive and negative if work is done on the fluid. Both the values of Q and W may be zero if heat is neither received nor rejected by the system or no work is done on or by the fluid.

The conservation of energy for the system may now be written;

$$E_{S1} + U_1 + P_1V_1 + KE_1 + PE_1 + Q = E_{S2} + U_2 + P_2V_2 + KE_2 + PE_2 + W \qquad (6.5)$$

Recognising the combination of terms $U + PV$ as the enthalpy and also that for a steady flow system the total energy of the fluid mass within the system, E_s remains constant, Equation 6.5 can be simplified to:-

$$Q - W = \left(H_2 - H_1 \right) + \left(KE_2 - KE_1 \right) + \left(PE_2 - PE_1 \right) \qquad (6.6)$$

Incorporating specific fluid properties and system geometry into Equation 6.6 yields:-

$$h_1 + \frac{C_1^2}{2g} + Z_1 + q = h_2 + \frac{C_2^2}{2g} + Z_2 + w \qquad (6.7)$$

where: h = enthalpy (kJ/kg)

C = velocity (m/s)

g = gravity constant (m/s²)

Z = height above datum (m)

q = heat (kJ/kg)

w = work (kJ/kg)

As there is no work performed on or by the furnace $w = 0$ and it can also be safely assumed that ΔZ, and $\Delta\left(\dfrac{C^2}{2}\right)$ from the feedwater inlet to the drum steam outlet are negligible compared to the change in enthalpy. Therefore Equation 6.7 can be simplified to:-

$$q = h_2 - h_1 \tag{6.8}$$

Equation 6.8 is to be used in conjunction with Equation 3.2, the Dulong formula, to form a ratio between the enthalpy change multiplied by the feedwater flow and the specific energy of the coal multiplied by the coal flow to give an estimate of the heat pick up and allow comparison between different boiler configurations. The furnace heat ratio formula is shown as Equation 6.9

$$Furnace\,Heat\,Ratio = \frac{\Delta h_{furnace} \times Feedwater\,Flow}{SE_{coal} \times Coal\,Flow} \tag{6.9}$$

6.5   An Engineering Model for Thermal NO_x Production

As stated in Chapter 5, the Zeldovich Mechanism can be used to describe the formation of thermal NO_x. With the fuel NO_x already produced during the combustion process, thermal NO_x becomes the main source of NO_x emissions where there is an excess of oxygen in the post-flame zone (Borman & Ragland, 1998).

To make use of the Zeldovich mechanism proper, the individual mole fractions of the O, N_2, NO, N, and O_2 species need to be determined. The required inputs to an equilibrium combustion product program provided by Turns (2000) are the number of carbon, hydrogen, and oxygen atoms, the equivalence ratio, the pressure and the flame temperature. The flame temperature is calculated using the input values from a typical coal type and boiler configuration used at Stanwell Power Station as follows:-

Percentage of carbon (daf)	88%
Percentage of hydrogen (daf)	4.91%
Percentage of nitrogen (daf)	1.88%
Percentage of sulphur (daf)	0.65%
Air flow	306 kg / s
Coal Flow	25.9 kg / s
Moisture content (wet but ash free)	8.63%
Calculated Temperature	2177 K

The inputs to the equilibrium combustion program by Turns (2000) are:-

Number of carbon atoms	580
Number of hydrogen atoms	771
Number of oxygen atoms	45
Number of nitrogen atoms	21
Equivalence ratio	0.823
Pressure	101 125 Pa
Temperature	2177 K

Running the program results in the following mole fractions of the equilibrium combustion products necessary for utilising the Zeldovich mechanism:-

Species	Mole Fraction
O	0.000427
O_2	0.0338
N_2	0.748
N	0.00000000816
NO	0.004957

The mole fraction of product species can be converted to a kmol/kg basis and combined with the rate mechanisms k_{+1}, k_{-1}, k_{+2}, k_{-2} to form the following overall rate mechanism for the formation of NO:-

$$\frac{d[NO]}{dt} = k_{+1}[O][N_2] - k_{-1}[NO][N] + k_{+2}[N][O_2] - k_{-2}[NO][O] \qquad (6.10)$$

Difficulties in using Equation 6.10 became apparent after multiplying the rate constants by a small time step to calculate an initial value for NO formed. It became necessary to recalculate the mole fractions of the combustion products. This

recalculation is the subject of complex chemical equilibrium (Turns, 2000) and as such is well beyond the scope of this project.

It is therefore necessary to simplify Equation 6.10 into a more convenient form. As the value of the N_2 and O_2 are much greater than the NO concentration, it can be safely assumed that these remain constant (Borman & Ragland, 1998). Also in processes where the combustion of the fuel is complete before NO production becomes significant, as is the case with the formation of thermal NO_x in the post-flame zone, the processes can be uncoupled. With sufficiently long time scales it is safe to assume that the N_2, O_2, and O concentrations are at equilibrium values and the N atoms are at steady state values. If the further assumption is made that the NO concentrations are much less than equilibrium values, that is, at the beginning of the post-flame zone the amount of NO formed by the thermal mechanism is zero, the reverse reactions can be ignored. This results in the following simple rate equation (Turns, 2000):-

$$\frac{d[NO]}{dt} = 2k_{+1}[O]_{eq}[N_2]_{eq}$$
(6.11)

Although this rate mechanism greatly simplifies the system and makes very broad and questionable simplifications, especially disregarding the presence of any NO in the immediate post-flame zone, for the purposes of this project it is considered sufficient. This simplified rate mechanism negates the complexities involved in the recalculation of the equilibrium combustion products.

An initial estimate of the rate of thermal NO_x formation can be made by dividing the furnace into a system of four separate zones of equal residence times as shown in Figure 6.5. The system inlet boundary is a horizontal plane extended across the furnace directly above the top windbox row as indicated by the horizontal line at the bottom of Zone 1. The outlet boundary of the system is a horizontal plane extending across the top of the furnace in line with the point of the furnace nose as indicated by the horizontal line at the top of Zone 4. Each zone will have an average combustion product temperature and initial O concentration. The species concentration of O will

be recalculated after each nominated time step by subtracting the amount of atoms used in the creation of the NO molecules.
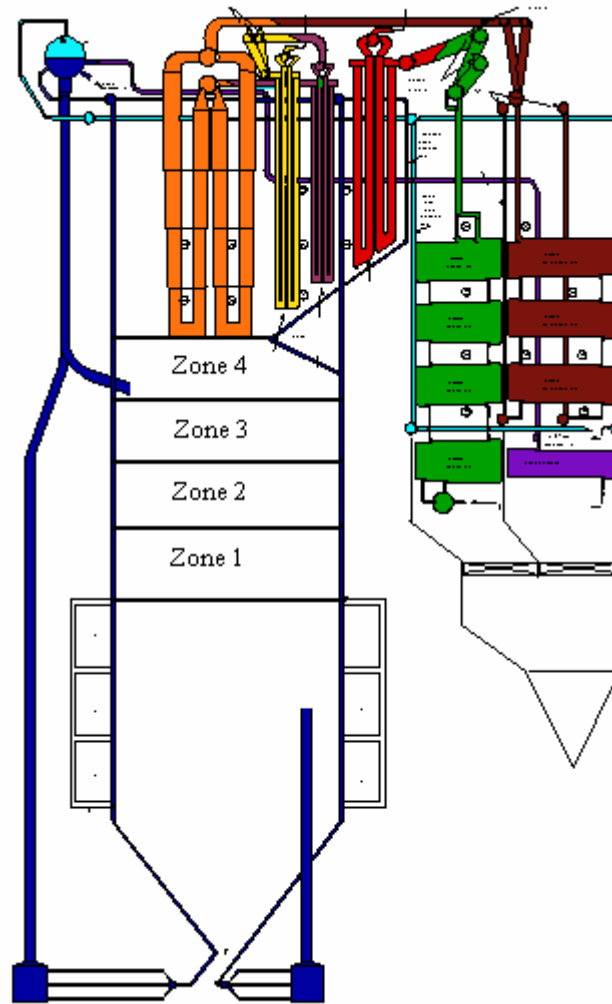
Figure 6.5 – Furnace Zones for Initial Thermal NO Prediction

As stated previously, to apply the rate mechanism, the mole fractions of the species of interest are converted to an average kmol/kg basis using the ideal gas law at an average furnace temperature as follows:-

$$n = \frac{Pv}{RT}$$ (6.12)

$$= \frac{101,125(1)}{8.314(1729)}$$

$$= 6.78 \frac{mole}{m^3}$$

where P = system pressure (Pa)

v = specific volume (m^3)

R = universal gas constant (kJ / kmol-k)

T = Zone temperature (K)

The molar concentration can now be expressed on a kmol / m^3 basis by multiplying the mole fraction of the species of interest by the number of moles occupying one (1) m^3 as determined by Equation 6.12.

The variables of interest for Zone 1 are as follows:-

Temperature (K)	2065
Residence Time (s)	0.82
Initial molar concentration of O (kmol/kg)	0.00000290
Molar concentration of N_2 (kmol/kg)	0.00507
Rate coefficient	1533
Time step (s)	0.05

Applying rate Equation 6.11 in the following form for a time step of 0.05 seconds results in the following:-

$$\Delta NO = 2\, k_{+1}\, [O]_{eq}\, [N_2]_{eq}\, \Delta t$$

$$= 2\,(1533)\,(2.90 \times 10^{-6})\,(5.07 \times 10^{-3})\,(0.05)$$

$$= 2.25 \times 10^{-6} \quad kmol/m^3$$

As the quantity of NO has increased, it is assumed that the amount of O remaining in the system has decreased by a similar amount resulting in:-

$$\mathrm{Re}\,maining\,[O] = 2.39 \times 10^{-6} - 2.25 \times 10^{-6}$$

$$= 0.14 \times 10^{-6} \quad kmol$$

This quantity of O is free to participate in NO formation during the second time step as follows:-

$$\Delta NO = 2\, k_{+1}\, [O]_{eq}\, [N_2]_{eq}\, \Delta t$$

$$= 2\,(1533)\,(0.14 \times 10^{-6})\,(5.07 \times 10^{-3})\,(0.05)$$

$$= 1.088 \times 10^{-7} \quad kmol/m^3$$

Similarly the third and fourth rates of formation for each time step can be determined resulting in:-

$$\Delta NO = 2.42 \times 10^{-8}$$

$$\Delta NO = 5.40 \times 10^{-9}$$

Plotting this data indicates a rapid formation of NO in the post-flame zone, reaching close to the initial value of the equilibrium O within a few time constants and still well within the Zone 1 residence time, as shown in Figure 6.6.
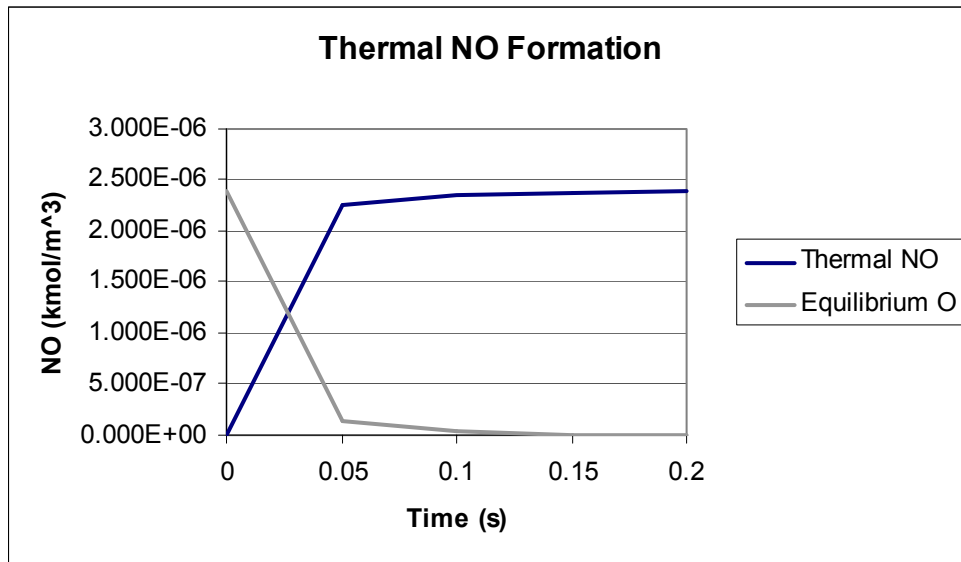
Figure 6.6 – Thermal NO Formation

Testing

7

7.1   Introduction

The purpose of the testing is to determine the sensitivity of NO_x emissions to variations of the usual operational configuration. Variations were made to the distribution of secondary air to the burner levels and also the amount of excess oxygen available within the furnace. Some of the data collected from the tests was compared to the predicted theoretical values from the models. Due to confidentiality issues, the values of NO emissions from Stanwell Power Station do not carry units and have been modified.

7.2   Variables of Interest

7.2.1 NO_x Production

As nitrogen oxide (NO) generally accounts for greater than 95% of the total NO_x emitted from coal-fired boilers (Electric Power Research Institute, 1993), the levels of raw NO were measured using the Sick GM 31 Emissions Monitoring System. This in-situ system allows gas to flow through the aperture of a probe installed into the flue duct. As the flue gases pass through the aperture, a deuterium lamp transmits pulses of ultraviolet light through the gas. The light then strikes a reflector which reflects the light back through the gas into the measuring unit. The GM 31 measures the attenuation of the light as a result of the absorption and dispersion in the mixture of gas and dust particles using the principle that gas molecules absorb light energy at wavelengths that are specific to the type of gas (GM 31 Operating Procedure, 1999). This allows the determination of the individual gas concentrations with a high degree of precision. The GM 31 measures the raw value of NO in the flue gas whereas the value for NO_x is calculated using the unit control and monitoring system using raw data including NO, NO_2, H_2O and O_2. Figure 7.1 shows the measuring principle of the GM 31 optical system.
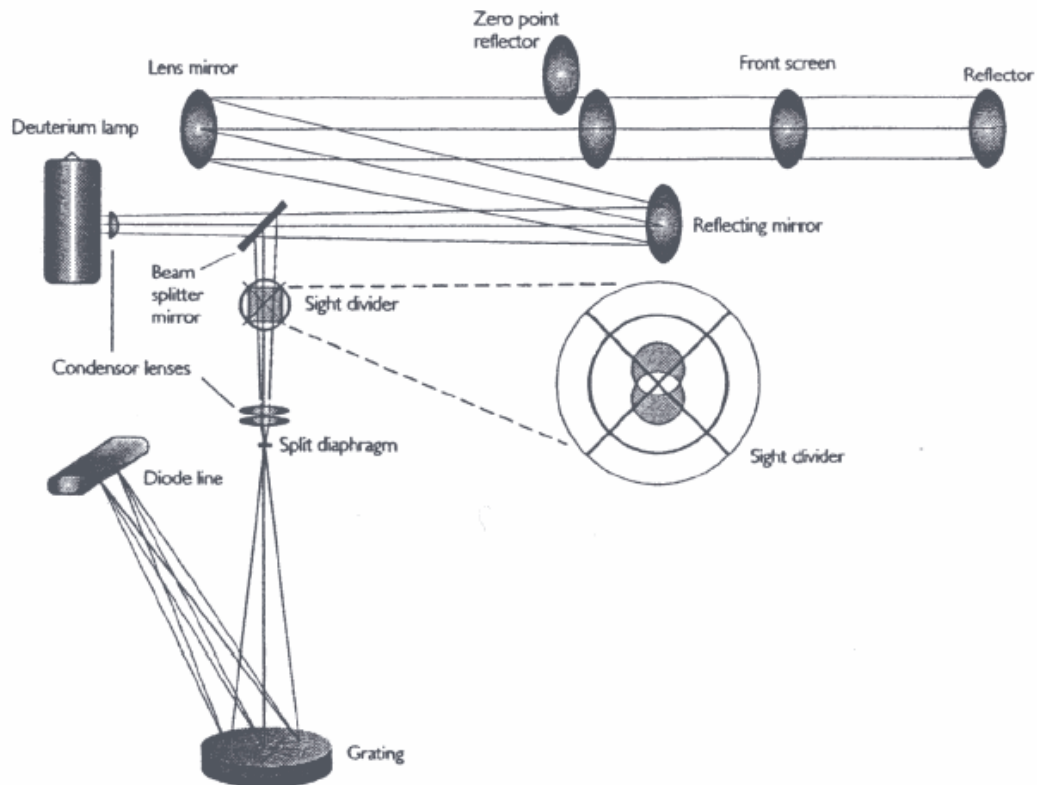
Figure 7.1 - Measuring Principle of GM 31
(Source: GM 31 Operating Procedure, 1999)

7.2.2   Flame Temperature

Flame and combustion product temperature measurements were taken using a Raynger 3i Series Infrared Thermometer. The thermometer uses a lens to focus infrared radiation from the combustion products onto a detector. The intensity of the emitted infrared energy increases or decreases proportionally to the temperature.

Three temperature measurements were taken through the furnace side port-holes in the fireball region including:-

1.   Temperature of the base of the flame as it exits the burner and first ignites;

2.   The furnace centre-line temperature where there is substantial mixing and interaction with the other burner flames; and

3. The water wall temperature adjacent to the end burners.

Other temperature measurements were recorded in the top and rear pass of the furnace including the platen superheater inlet and outlet temperatures, the exit of the Secondary Superheater II and the furnace throat. Figure 7.2 details the location of the test points at the side of the furnace relating to this project. Temperatures were taken on both sides in the furnace area, and at five points along the boiler front at the platen entries.
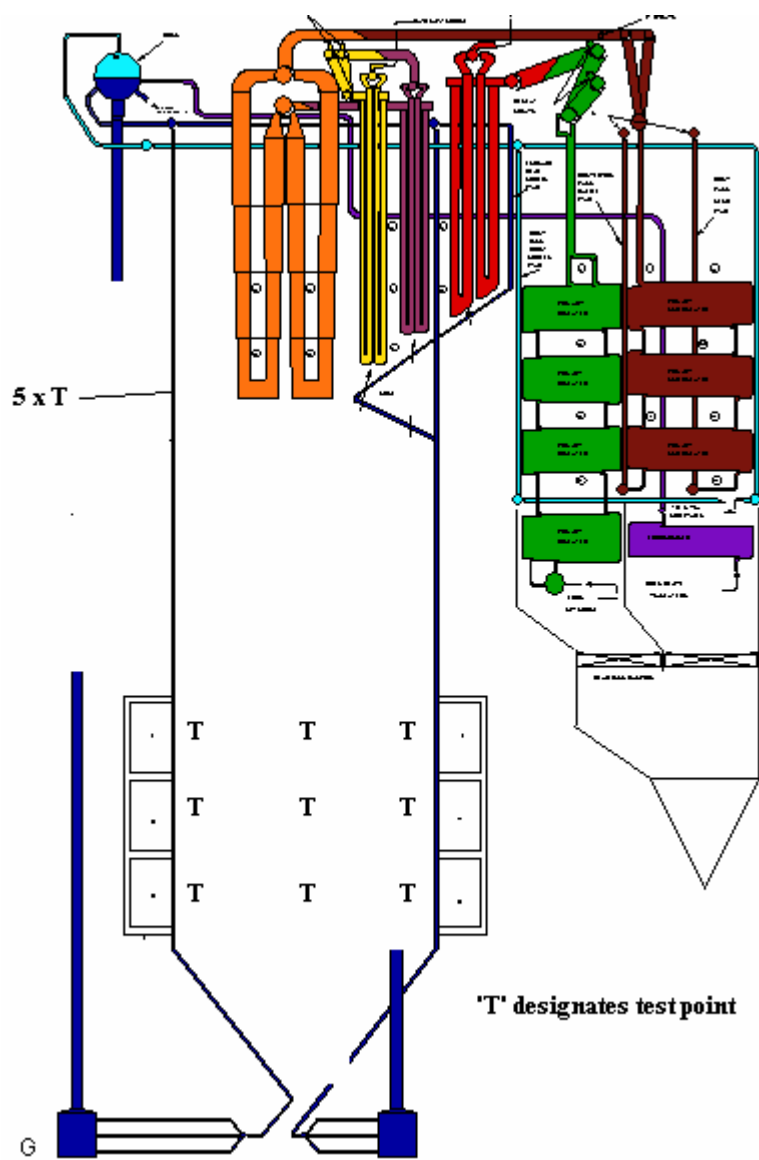
Figure 7.2 – Location of Temperature Measurement Points

7.2.3   Coal Sampling

A sample of the coal burnt during each of the tests was taken by removing a quantity of coal from one of the in-service coal feeder belts. The samples were then sent to an external laboratory for ultimate analysis.

7.2.4   Loss of Ignition

Loss of ignition refers to losses in the form of combustibles passing out in the flue gas and may result from insufficient oxygen available for combustion or poor mixing of the reactants. As the volatiles are driven off and react early in the combustion process, the predominant losses will occur as a result of unburnt carbon in the flue gas. Low levels of unburnt carbon passing out in the flue gas equate to a loss of efficiency whilst high levels of unburnt carbon not only result in efficiency losses but also create a potentially hazardous situation with regard to fire and explosion in the rear pass of the boiler.

The fly ash was sampled using a Cegrit manual sampler which extracts fly ash as it passes through the flue gas ductwork prior to it passing through the electrostatic precipitators. The flue gas carrying the fly ash is drawn continuously through a cyclone by an ejector device mounted in the duct. The cyclone effectively separates the gas and the solids with the solids falling into a sampling container clamped to the bottom of the cyclone. From here the composition of the solids can be analysed to determine the combustible content. Figure 7.3 details the components of the Cegrit sampler.
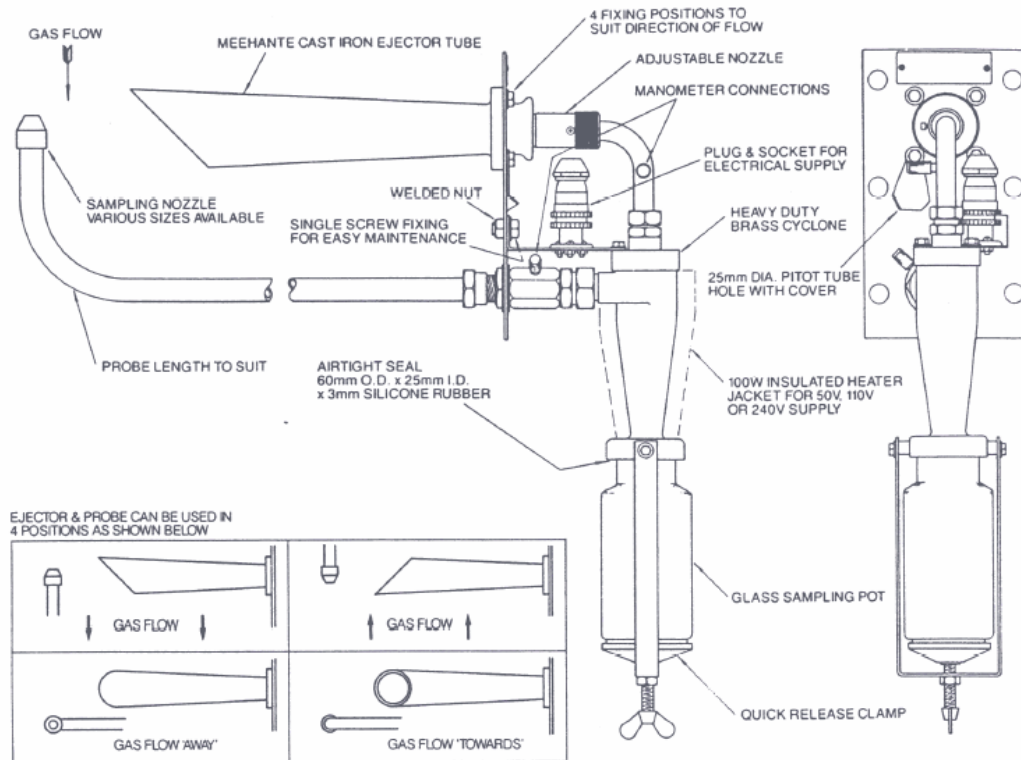
Figure 7.3 – Cegrit Sampler
(Source: Airflow Developments Operating Procedure, n.d.)

7.2.5   Furnace Heat Pickup

As described in section 6.4 the furnace heat pickup can be determined by the change in enthalpy as the feedwater leaving the economiser inlet is transformed within the furnace water walls to steam leaving the drum. The temperature of the feedwater leaving the economiser and the drum (system) pressure are available from the boiler control system. The values of the enthalpy at the system inlet and outlet are to be determined from the steam charts by the Japan Society of Mechanical Engineers (1980) to determine the amount of heat transferred to the furnace water walls. The mass flow rate of feedwater into the system and the mass flow rate of the coal delivered to the mill are also available from the boiler operating system to allow the calculation of the furnace heat pickup.

7.2.6   Economiser Excess Oxygen

As the combustion products leave the furnace after passing through the economiser area, the flow of gas is split so that equal amounts of gas pass through each of the air heaters. Two oxygen transmitters are located on both 'A' and 'B' sides prior to entry to the air heaters to monitor the levels of excess oxygen. The actual excess oxygen set point is determined by the control system which averages the value of the two same side transmitters then bases the air flow delivered by the forced draught fans on the minimum of these two values. In manual operation the blade pitch on the forced draft fans can then be altered until the required excess oxygen levels for the test are achieved. As a consequence of this logic arrangement the actual excess oxygen levels will always be greater than the O_2 level displayed by the boiler control system. Figure 7.4 details the control logic for the transmitters in setting the required O_2 level.
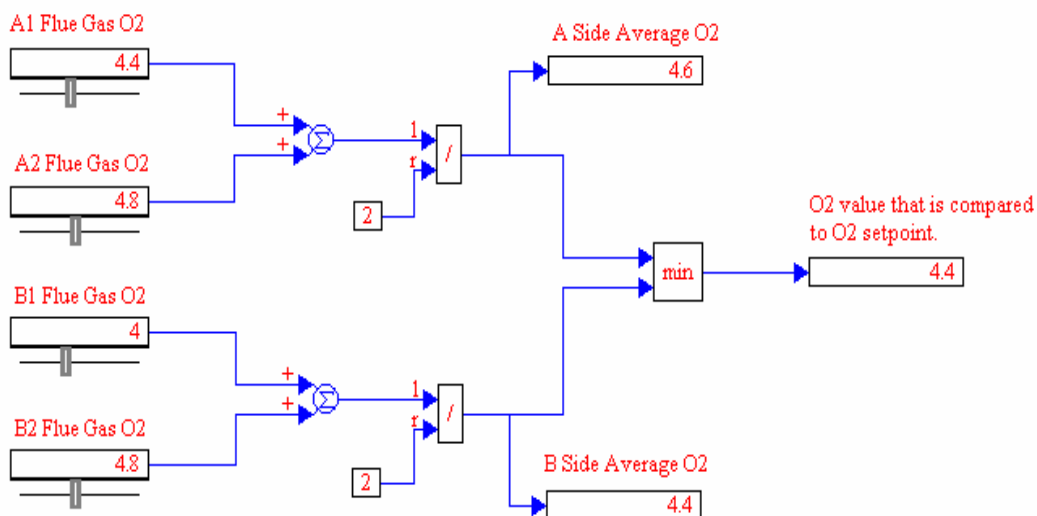
Figure 7.4 – Excess Oxygen Control Logic

7.3   Secondary Air Redistribution

7.3.1   Aim

Tests 1, 2 and 3 were undertaken to examine the effect on the variables of interest of redistributing in-service secondary air among the in-service burners whilst maintaining a constant ratio of in-service secondary air to out-of-service secondary air.

7.3.2   Testing Method

The boiler at Stanwell Power Station is a horizontally opposed configuration with three levels of burner rows located front and back of the furnace. Each burner row comprises five pulverised fuel burners similar to the furnace depicted in Figure 7.5.
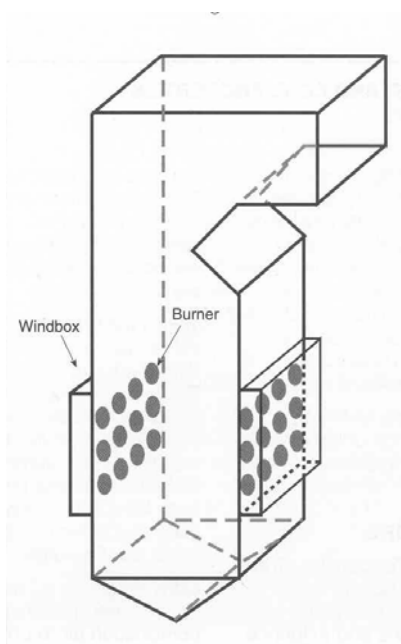
Figure 7.5 – Opposed Wall Fired Boiler
(Source: EPRI Retrofit NO$_x$ Controls for Coal-Fired Utility Boilers, 1993, p3-4)

Located at the ends of each row of five burners are a pair of windbox dampers that control the amount of secondary air flow to each of the burner windboxes. These six sets of windbox dampers have a range of operation between 40% and 100% and can be adjusted to achieve the desired test position.

7.3.3 Testing Assumptions

The following assumptions were made for these series of tests:-

1. Uniform secondary air duct static pressure and therefore a constant position to flow relationship irrespective of burner level.

2. To maintain a constant ratio of in-service to out-of-service secondary air, assume a linear damper position to flow relationship. For example, the opening of one in-service windbox damper pair 15% to be compensated by closing the three remaining in-service windbox damper pairs by 5% each.

7.3.4 Specific Requirements

1. Test duration to be 1.5 hours minimum.

2. Allow 30 minutes after dampers are adjusted to allow boiler to stabilise before commencing testing.

3. Coal samples to be taken at commencement and conclusion of each test to check for variations in quality during test.

7.3.5 Boiler Conditioning

The following plant conditioning was required:-

- 270 MW – a steady load is required to allow comparable results to be obtained.

- Automatic Governor Control (AGC) de-selected – this step is required to stop the market traders altering the output from the unit in response to changes in the national electricity market.

- Boiler Load Set Point (BLSP) – the generator output is governed by the steam flow from the boiler.

- Calorific Value (CV) trim to manual – this step will result in a steady mass flow of coal being delivered to each of the four in-service mills.

- O_2 trim to manual – this step fixes the position of the forced draft fans and results in a steady mass flow of air to the boiler.

- No soot blowing to be performed during testing – soot blowing uses steam produced in the boiler resulting in reduced steam flow to the turbines and increased heat pick up from the areas that have been cleaned. Water vapour will also be present in the flue gas and affect the fly ash samples.

7.4   Test 1

A baseline test was performed to determine the value of the variables of interest under normal operating conditions. These windbox damper positions are those that were identified and incorporated into the control system during unit commissioning as detailed in Table 7.1.

Dampers	In Service Position	Out of Service Position
F1-F2		45%
A1-A2	70%	
B1-B2	85%	
E1-E2	45%	
C1-C2	70%	
D1-D2		45%

Table 7.1 – Test 1 Windbox Damper Positions

Table 7.2 details the maximum and average temperatures from the test points described in section 7.2.2 as well as the values from the control system used to determine plant performance.

Maximum Values					
Top Row	Maximum	1358	**Top Row Centreline**	Maximum	1430
	Minimum	1314		Minimum	1430
	Mean	1336		Mean	1430
	Range	44		Range	0
Middle Row	Maximum	1405	**Middle Row Centreline**	Maximum	1431
	Minimum	1294		Minimum	1408
	Mean	1360.5		Mean	1419.5
	Range	111		Range	23
Bottom Row	Maximum	1355	**Bottom Row Centreline**	Maximum	1408
	Minimum	1198		Minimum	1278
	Mean	1276.5		Mean	1343
	Range	157		Range	130
Average Values					
Top Row	Maximum	1330	**Top Row Centreline**	Maximum	1416
	Minimum	1292		Minimum	1388
	Mean	1311		Mean	1402
	Range	38		Range	28
Middle Row	Maximum	1354	**Middle Row Centreline**	Maximum	1399
	Minimum	1254		Minimum	1394
	Mean	1297		Mean	1397
	Range	100		Range	5
Bottom Row	Maximum	1280	**Bottom Row Centreline**	Maximum	1280
	Minimum	1241		Minimum	1254
	Mean	1261		Mean	1267
	Range	39		Range	26
Performance Data					
Furnace Exit Gas Temperature (C)		1028	**Platen Entry Temperature**	Maximum	1104
				Average	1040
Drum Saturation Temperature (C)		344	**Drum Pressure (Mpa)**		15.14
Economiser Outlet Temperature (C)		263.7	**Feedwater Flow (kg/s)**		217.7
Loss of Ignition (%)		1.7	**Total Air Flow (kg/s)**		306
NO Level		0.649	**Total Fuel Flow (kg/s)**		25.9

Table 7.2 – Test 1 Data

7.5 Test 2

A "square" in-service windbox pattern was trialled for Test 2 with all of the in-service windboxes set to 67% as detailed in Table 7.3.

Dampers	In Service Position	Out of Service Position
F1-F2		45%
A1-A2	67%	
B1-B2	67%	
E1-E2	67%	
C1-C2	67%	
D1-D2		45%

Table 7.3 – Test 2 Windbox Damper Positions

Table 7.4 details the maximum and average temperatures from the test points described in section 7.2.2 as well as the values from the control system used to determine plant performance.

Maximum Values						
Top Row	Maximum	1379	**Top Row Centreline**		Maximum	1485
	Minimum	1364			Minimum	1468
	Mean	1371.5			Mean	1476.5
	Range	15			Range	17
Middle Row	Maximum	1317	**Middle Row Centreline**		Maximum	1458
	Minimum	1288			Minimum	1450
	Mean	1306.75			Mean	1454
	Range	29			Range	8
Bottom Row	Maximum	1319	**Bottom Row Centreline**		Maximum	1335
	Minimum	1317			Minimum	1316
	Mean	1318			Mean	1325.5
	Range	2			Range	19
Average Values						
Top Row	Maximum	1330	**Top Row Centreline**		Maximum	1462
	Minimum	1320			Minimum	1451
	Mean	1325			Mean	1457
	Range	10			Range	11
Middle Row	Maximum	1297	**Middle Row Centreline**		Maximum	1430
	Minimum	1212			Minimum	1427
	Mean	1255			Mean	1429
	Range	85			Range	3
Bottom Row	Maximum	1231	**Bottom Row Centreline**		Maximum	1294
	Minimum	1210			Minimum	1290
	Mean	1221			Mean	1292
	Range	21			Range	4
Performance Data						
Furnace Exit Gas Temperature (C)		1057	**Platen Entry Temperature**		Maximum	1112
					Average	1081
Drum Saturation Temperature (C)		344.1	**Drum Pressure (Mpa)**			15.44
Economiser Outlet Temperature (C)		263.4	**Feedwater Flow (kg/s)**			224
Loss of Ignition (%)		3.2	**Total Air Flow (kg/s)**			298
NO Level		0.649	**Total Fuel Flow (kg/s)**			26

Table 7.4 – Test 2 Data

7.6   Test 3

An "inverted" windbox pattern was trialled for Test 3 with upper level in-service windbox opened to 80%, the lower level in-service windbox closed in to 50%, and middle windboxes left at 70% as detailed in Table 7.5. With the top in-service windbox opened to 80% and larger quantities of secondary air provided high in the furnace, it is expected a rise in furnace exit gas temperature will ensue. It is also predicted that burnout of the fuel will be high resulting in low carbon in fly ash losses.

Dampers	In Service Position	Out of Service Position
F1-F2		50%
A1-A2	70%	
B1-B2	50%	
E1-E2	80%	
C1-C2	70%	
D1-D2		50%

Table 7.5 – Test 3 Windbox Damper Positions

Table 7.6 details the maximum and average temperatures from the test points described in section 7.2.2 as well as the values from the control system used to determine plant performance.

Maximum Values					
Top Row	Maximum	1374	**Top Row Centreline**	Maximum	1451
	Minimum	1353		Minimum	1451
	Mean	1363.5		Mean	1451
	Range	21		Range	0
Middle Row	Maximum	1423	**Middle Row Centreline**	Maximum	1450
	Minimum	1295		Minimum	1414
	Mean	1361.25		Mean	1432
	Range	128		Range	36
Bottom Row	Maximum	1329	**Bottom Row Centreline**	Maximum	1358
	Minimum	1318		Minimum	1333
	Mean	1323.5		Mean	1345.5
	Range	11		Range	25
Average Values					
Top Row	Maximum	1331	**Top Row Centreline**	Maximum	1428
	Minimum	1322		Minimum	1406
	Mean	1327		Mean	1417
	Range	9		Range	22
Middle Row	Maximum	1389	**Middle Row Centreline**	Maximum	1442
	Minimum	1226		Minimum	1394
	Mean	1309		Mean	1418
	Range	163		Range	48
Bottom Row	Maximum	1250	**Bottom Row Centreline**	Maximum	1321
	Minimum	1245		Minimum	1308
	Mean	1248		Mean	1315
	Range	5		Range	13
Performance Data					
Furnace Exit Gas Temperature (C)		1032	**Platen Entry Temperature**	Maximum	1119
				Average	1038
Drum Saturation Temperature (C)		344	**Drum Pressure (Mpa)**		15.14
Economiser Outlet Temperature (C)		264.6	**Feedwater Flow (kg/s)**		216.8
Loss of Ignition (%)		0.8	**Total Air Flow (kg/s)**		306
NO Level		0.652	**Total Fuel Flow (kg/s)**		25.9

Table 7.6 – Test 3 Data

7.7   Test 4

7.7.1   Aim

This test was undertaken to simulate the effects of over-fire air by opening the top out-of-service windbox whilst closing all other windboxes. The assumptions, specific requirements and boiler conditioning remain the same as the previous series of tests. The top out-of-service damper was opened to 80% position for this test with all other in-service dampers closed in 5% each as shown in Table 7.7. There was a concern that the large quantity of secondary air being emitted from 'F' row may force the flames from the in-service 'E' row back onto the water wall causing a temperature differential from furnace front to back and poor flame stability. To alleviate this potential risk, the flame detection system was constantly monitored during the preparations for this test.

Dampers	In Service Position	Out of Service Position
F1-F2		80%
A1-A2	65%	
B1-B2	80%	
E1-E2	40%	
C1-C2	65%	
D1-D2		40%

Table 7.7 – Test 4 Windbox Damper Positions

Table 7.8 details the maximum and average temperatures from the test points described in section 7.2.2 as well as the values from the control system used to determine plant performance.

Maximum Values					
Top Row	Maximum	1369	**Top Row Centreline**	Maximum	1431
	Minimum	1312		Minimum	1420
	Mean	1340.5		Mean	1425.5
	Range	57		Range	11
Middle Row	Maximum	1421	**Middle Row Centreline**	Maximum	1412
	Minimum	1270		Minimum	1410
	Mean	1349		Mean	1411
	Range	151		Range	2
Bottom Row	Maximum	1329	**Bottom Row Centreline**	Maximum	1295
	Minimum	1312		Minimum	1276
	Mean	1320.5		Mean	1285.5
	Range	17		Range	19
Average Values					
Top Row	Maximum	1335	**Top Row Centreline**	Maximum	1408
	Minimum	1259		Minimum	1397
	Mean	1297		Mean	1403
	Range	76		Range	11
Middle Row	Maximum	1346	**Middle Row Centreline**	Maximum	1382
	Minimum	1198		Minimum	1370
	Mean	1272		Mean	1376
	Range	148		Range	12
Bottom Row	Maximum	1260	**Bottom Row Centreline**	Maximum	1274
	Minimum	1219		Minimum	1247
	Mean	1240		Mean	1261
	Range	41		Range	27
Performance Data					
Furnace Exit Gas Temperature (C)		1028	**Platen Entry Temperature**	Maximum	1135
				Average	1086
Drum Saturation Temperature (C)		15.2	**Drum Pressure (Mpa)**		15.2
Economiser Outlet Temperature (C)		262.2	**Feedwater Flow (kg/s)**		218.6
Loss of Ignition (%)		5.9	**Total Air Flow (kg/s)**		303
NO Level		0.601	**Total Fuel Flow (kg/s)**		26

Table 7.8 – Test 4 Data

7.8   Variation in Excess Air

7.8.1   Aim

Tests 5, 6 and 7 examine the effect on the variables of interest of the levels of excess oxygen. The amount of combustion air provided to the furnace can be varied by altering the pitch on the forced draught fans until the desired excess oxygen levels are achieved at the economiser cross over.

7.8.2   Assumptions

1.   The excess oxygen set point was determined from the values given by the control logic as described in section 7.2.6.

7.8.3   Specific Requirements

1.   Test duration to be 1.5 hours minimum.

2.   Allow 30 minutes after required excess oxygen level has been achieved to allow boiler to stabilise before commencing testing.

3.   Coal samples to be taken at commencement and conclusion of each test to check for variations in quality during test.

7.9   Test 5

The amount of secondary air provided to the furnace was altered until an excess oxygen level of three percent was achieved.

Table 7.9 details the maximum and average temperatures from the test points described in section 7.2.2 as well as the values from the control system used to determine plant performance.

Maximum Values					
Top Row	Maximum	1328	**Top Row Centreline**	Maximum	1489
	Minimum	1309		Minimum	1475
	Mean	1318.5		Mean	1482
	Range	19		Range	14
Middle Row	Maximum	1364	**Middle Row Centreline**	Maximum	1451
	Minimum	1287		Minimum	1450
	Mean	1338		Mean	1450.5
	Range	77		Range	1
Bottom Row	Maximum	1291	**Bottom Row Centreline**	Maximum	1351
	Minimum	1277		Minimum	1338
	Mean	1284		Mean	1344.5
	Range	14		Range	13
Average Values					
Top Row	Maximum	1335	**Top Row Centreline**	Maximum	1476
	Minimum	1252		Minimum	1408
	Mean	1294		Mean	1442
	Range	83		Range	68
Middle Row	Maximum	1348	**Middle Row Centreline**	Maximum	1444
	Minimum	1198		Minimum	1434
	Mean	1300		Mean	1439
	Range	150		Range	10
Bottom Row	Maximum	1223	**Bottom Row Centreline**	Maximum	1323
	Minimum	1219		Minimum	1300
	Mean	1221		Mean	1312
	Range	4		Range	23
Performance Data					
Furnace Exit Gas Temperature (C)		1064	**Platen Entry Temperature**	Maximum	1164
				Average	1138
Drum Saturation Temperature (C)		345.2	**Drum Pressure (Mpa)**		15.37
Economiser Outlet Temperature (C)		257	**Feedwater Flow (kg/s)**		216.4
Loss of Ignition (%)		7.3	**Total Air Flow (kg/s)**		274
NO Level		0.532	**Total Fuel Flow (kg/s)**		26.4

Table 7.9 – Test 5 Data

7.10   Test 6

The amount of secondary air provided to the furnace is to be altered until an excess oxygen level of four percent is achieved.

Table 7.10 details the maximum and average temperatures from the test points described in section 7.2.2 as well as the values from the control system used to determine plant performance.

Maximum Values					
Top Row	Maximum	1315	**Top Row Centreline**	Maximum	1460
	Minimum	1279		Minimum	1440
	Mean	1297		Mean	1450
	Range	36		Range	20
Middle Row	Maximum	1373	**Middle Row Centreline**	Maximum	1383
	Minimum	1324		Minimum	1356
	Mean	1347.75		Mean	1369.5
	Range	49		Range	27
Bottom Row	Maximum	1297	**Bottom Row Centreline**	Maximum	1292
	Minimum	1292		Minimum	1250
	Mean	1294.5		Mean	1271
	Range	5		Range	42
Average Values					
Top Row	Maximum	1240	**Top Row Centreline**	Maximum	1440
	Minimum	1220		Minimum	1420
	Mean	1230		Mean	1430
	Range	20		Range	20
Middle Row	Maximum	1350	**Middle Row Centreline**	Maximum	1370
	Minimum	1170		Minimum	1345
	Mean	1255		Mean	1358
	Range	180		Range	25
Bottom Row	Maximum	1230	**Bottom Row Centreline**	Maximum	1250
	Minimum	1190		Minimum	1235
	Mean	1210		Mean	1243
	Range	40		Range	15
Performance Data					
Furnace Exit Gas Temperature (C)		1057	**Platen Entry Temperature**	Maximum	1116
				Average	1091
Drum Saturation Temperature (C)		345.6	**Drum Pressure (Mpa)**		15.44
Economiser Outlet Temperature (C)		263.3	**Feedwater Flow (kg/s)**		227.3
Loss of Ignition (%)		10.9	**Total Air Flow (kg/s)**		294
NO Level		0.545	**Total Fuel Flow (kg/s)**		26.4

Table 7.10 – Test 6 Data

7.11   Test 7

The amount of secondary air provided to the furnace is to be altered until an excess oxygen level of 5½ per cent is achieved.

Table 7.11 details the maximum and average temperatures from the test points described in section 7.2.2 as well as the values from the control system used to determine plant performance.

Maximum Values					
Top Row	Maximum	1310	**Top Row Centreline**	Maximum	1436
	Minimum	1298		Minimum	1408
	Mean	1304		Mean	1422
	Range	12		Range	28
Middle Row	Maximum	1411	**Middle Row Centreline**	Maximum	1370
	Minimum	1179		Minimum	1338
	Mean	1295.25		Mean	1354
	Range	232		Range	32
Bottom Row	Maximum	1316	**Bottom Row Centreline**	Maximum	1245
	Minimum	1305		Minimum	1220
	Mean	1310.5		Mean	1232.5
	Range	11		Range	25
Average Values					
Top Row	Maximum	1290	**Top Row Centreline**	Maximum	1395
	Minimum	1238		Minimum	1359
	Mean	1264		Mean	1377
	Range	52		Range	36
Middle Row	Maximum	1376	**Middle Row Centreline**	Maximum	1338
	Minimum	1131		Minimum	1322
	Mean	1254		Mean	1330
	Range	245		Range	16
Bottom Row	Maximum	1266	**Bottom Row Centreline**	Maximum	1222
	Minimum	1257		Minimum	1193
	Mean	1262		Mean	1208
	Range	9		Range	29
Performance Data					
Furnace Exit Gas Temperature (C)		991	**Platen Entry Temperature**	Maximum	1083
				Average	1054
Drum Saturation Temperature (C)		345.3	**Drum Pressure (Mpa)**		15.38
Economiser Outlet Temperature (C)		266.5	**Feedwater Flow (kg/s)**		221
Loss of Ignition (%)		6.1	**Total Air Flow (kg/s)**		318
NO Level		0.624	**Total Fuel Flow (kg/s)**		26.4

Table 7.11 – Test 7 Data

7.12   Testing Difficulties

Ten (10) tests were actually undertaken however problems including failure of the test equipment, sootblowing during testing and major changes in coal quality rendered the results from some tests invalid and as such these tests had to be repeated.

Planning and undertaking each of the tests required a significant amount of time and resources due to the following reasons:-

- Ensuring all test equipment was functional
- Ensuring operational staff were aware of boiler set up
- Market trading staff were aware of testing
- Time taken to adjust boiler to the required test position and allowing boiler to stabilise
- Time taken to perform temperature survey and collect samples

Results

8

8.1   Introduction

This chapter details the results obtained through the testing phase of the project. Predicted flame temperatures are compared with measured values.   The loss of ignition and furnace heat pickup are compared between tests carried out.   The difficulties encountered with thermal NO prediction are outlined and the actual measured values of NO are compared between tests. Appendix D details some of the data used in the calculation of the variables used to create the graphs in this section.

8.2   Flame Temperature Comparison

A series of comparisons were performed to determine the validity of the flame temperature estimates described in section 6.3. Figure 8.1 shows the calculated flame temperature values compared to the values measured around the furnace. The measured values are the mean maximum centre-line temperatures measured at the top burner level and the average centreline temperature measured from the same location. As can be seen from Figure 8.1, the calculated flame temperature is approximately 450˚C above the measured values and does not appear to follow the trend of the measured values.
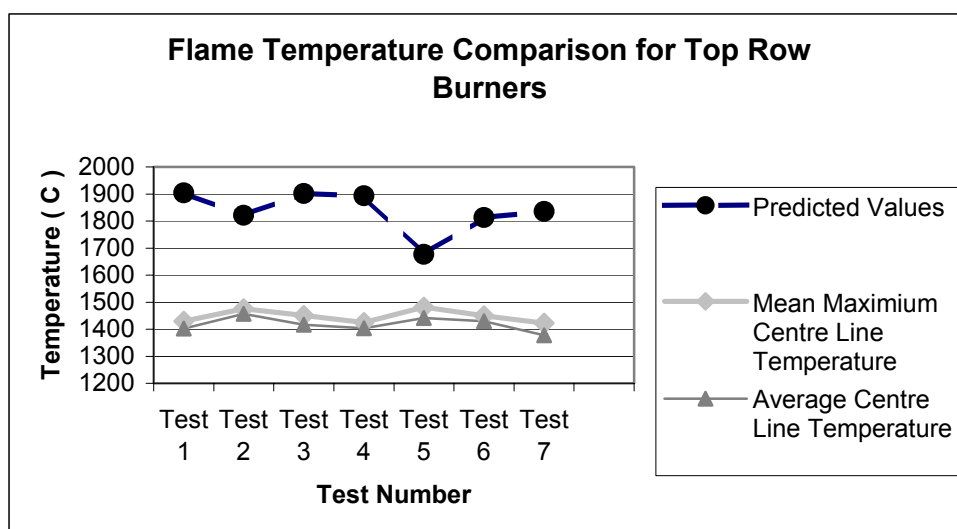

Figure 8.1 – Comparison of Predicted and Measured Temperatures for Top Row Burners

Figure 8.2 shows a similar comparison using the measured values from the bottom row of burners. Even in the lower burner region where the flame is less affected by surrounding flames, the values of the predicted temperatures still appear to show no trend compared to the measured values. The calculation of the flame temperature using the method described by Field et al (1967) does not accurately reflect the conditions found within the furnace at Stanwell. As such the temperature distributions used in the NO calculations used the values determined through testing.
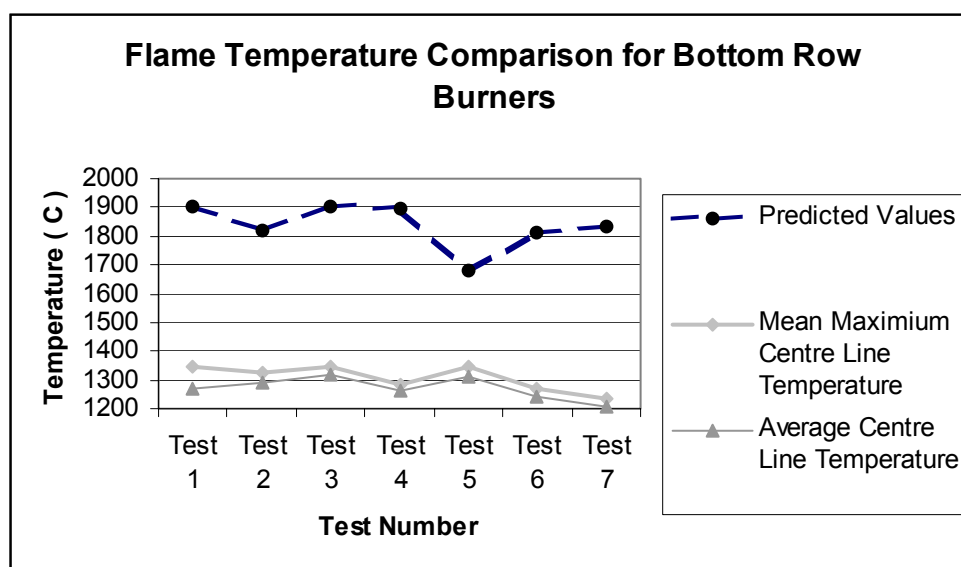
Figure 8.2 – Comparison of Predicted and Measured Temperatures for Bottom Row Burners

8.3   Loss of Ignition

Figure 8.3 shows the loss of ignition (LOI) for each of the tests. The lowest value of LOI achieved was for Test 3 with a value of 0.8%. This high burnout was achieved when a large amount of secondary air was admitted high in the furnace. It is not known how much unburnt carbon was present in the bottom ash, however as bottom ash generally accounts for less than 10% of total ash it would not account for a significant loss. It is interesting to note that the windbox damper position for Tests 5, 6 and 7 was the same as baseline Test 1 yet the LOI for these tests was significantly more. These tests had a greater amount of ash present in the coal which may have

hindered acceptable burnout. The result for Test 6 was unexpected as the LOI levels were expected to fall somewhere between the levels measured for Test 5 and 7. It appears that coal quality significantly affects loss of ignition.
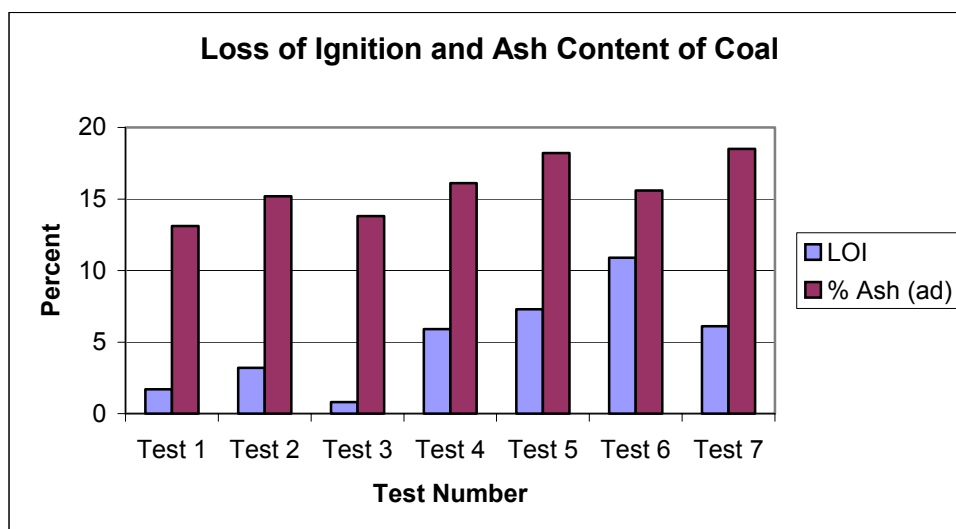
Figure 8.3 – Loss of Ignition and Ash Content of Coal

8.4 Furnace Heat Pickup

Table 8.1 shows the steps undertaken to determine the enthalpy added to the feedwater to transform it to a saturated steam. The value of the drum pressure was gathered from the control system and the corresponding saturation temperature calculated by interpolating the values from the JSME steam tables. The liquid enthalpy change in raising the feedwater to a saturated liquid was determined and added to the enthalpy of evaporation required to raise the mix to a saturated vapour to determine the total change in enthalpy (Joel, 1996).

Test No.	Drum Pressure (Mpa)	Saturation Temperature (°C)	Economiser Outlet Temperature (°C)	Enthalpy Change in Raising Water to Saturation Temperature (kJ/kg)	Enthalpy of Evaporation (kJ/kg)	Total Change in Enthalpy (kJ/kg)
Test 1	15.14	342.9	263.7	464.4	2,610.9	3,075.3
Test 2	15.16	343.0	263.4	466.6	2,610.3	3,076.9
Test 3	15.14	342.9	264.6	460.1	2,610.9	3,071.0
Test 4	15.20	343.2	262.2	473.9	2,609.1	3,083.0
Test 5	15.37	344.1	257.0	505.8	2,604.1	3,109.9
Test 6	15.44	344.4	263.3	477.6	2,602.1	3,079.7
Test 7	15.38	344.1	266.5	459.8	2,603.8	3,063.6

Table 8.1 – Enthalpy Change from Economiser Outlet to Boiler Drum Steam Outlet

The furnace heat ratio was determined to evaluate how much of the heat produced during the combustion of the pulverised coal was transferred to the water walls. The ratio was formed in the following way:-

1. The numerator was formed by multiplying the total change in enthalpy as described above by the feedwater flow.

2. The denominator was formed by multiplying the specific energy of the coal as determined from the Dulong formula (Equation 3.2) by the mass flow rate of the coal.

The higher the value of the furnace heat ratio indicates an improvement in heat transfer. Table 8.2 details the calculation of the furnace heat ratio for each of the tests undertaken.

Test No.	Total Change in Enthalpy (kJ/kg)	Feed Water Flow (kg/s)	Total Change in Enthalpy multiplied by Feed Water Flow (kJ/s)	Specific Energy of Coal from Dulong Formula (kJ/kg)	Coal Flow Rate (kg/s)	Specific Energy of Coal multiplied by Coal Flow Rate (kJ/s)	Furnace Heat Ratio
Test 1	3,075.3	217.7	669,493	36,100	25.9	934,990	0.716
Test 2	3,076.9	224.0	689,226	36,190	26.0	940,940	0.732
Test 3	3,071.0	216.8	665,793	36,250	25.9	938,875	0.709
Test 4	3,083.0	218.6	673,944	35,860	26.0	932,360	0.723
Test 5	3,109.9	216.4	672,982	36,350	26.4	959,640	0.701
Test 6	3,079.7	227.3	700,016	36,130	26.4	953,832	0.734
Test 7	3,063.6	221.0	677,056	35,940	26.4	948,816	0.714

Table 8.2 – Furnace Heat Ratio

Figure 8.4 shows the furnace heat ratio and the specific energy of the coal for each of the tests undertaken. The furnace heat ratio was greatest for Test 6 with an excess air level of 4%. It is interesting to note the result for Test 4, the over-fire air simulation, which achieved favourable furnace heat pickup using a coal of low specific energy.
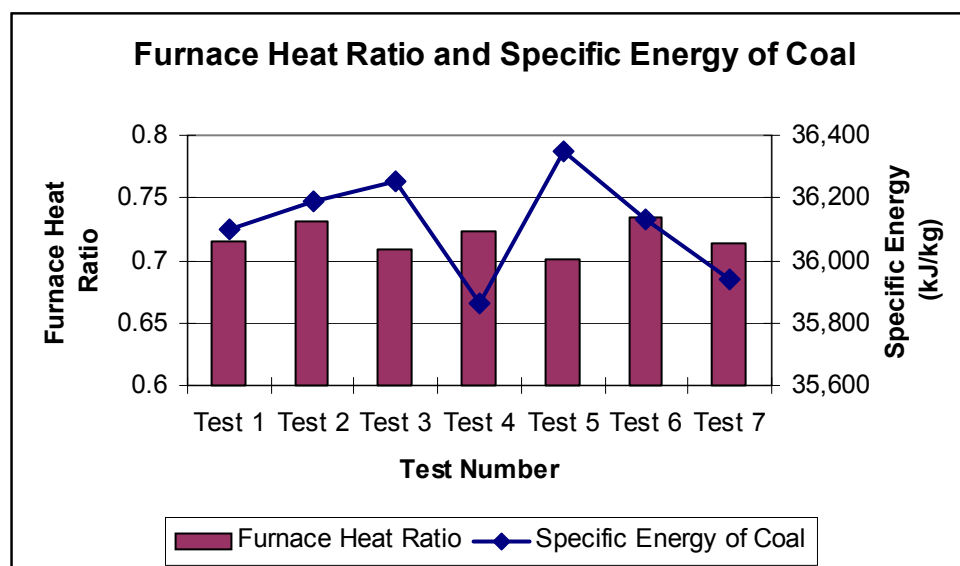
Figure 8.4 – Furnace Heat Ratio and Specific Energy of Coal

8.5   Thermal NO Prediction

The prediction of thermal NO proved to be difficult and time consuming with no accurate measures or results achieved. As stated in Chapter 5, thermal NO generally accounts for 20% to 50% of total NO_x emissions. Using the measured temperatures from Test 1, the results from the ultimate analysis of the coal and the equilibrium combustion program from Turns (2000) results in a minuscule amount of monatomic oxygen being produced. The rate coefficient determined at these temperatures was not large enough to counter the small amounts of monatomic oxygen, therefore the values of NO predicted are insignificant, being many orders of magnitude less than expected. The model was developed assuming basic plug flow and it was not considered a worthwhile exercise to incorporate the residence time estimate into the model. This same result was obtained for all of the tests. Figure 8.5 shows the predicted rate of NO for Test 1.
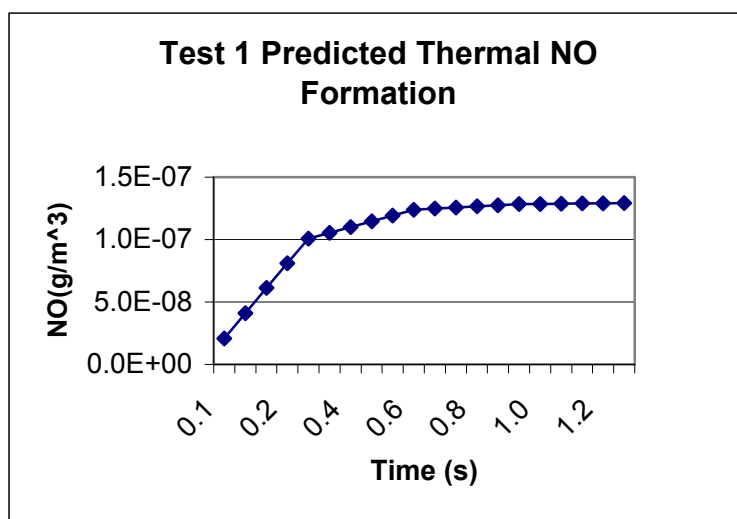
Figure 8.5 – Predicted NO for Test 1

Even when the model is used to predict thermal NO at flame temperatures far greater than those recorded there was still not enough monatomic oxygen created in the system to yield expected values of NO.

Some of the possible reasons for the low values of NO may be:-

1. It is possible that the assumption of an instantaneous conversion of the reactants to the products of combustion is not valid for this system and that diatomic oxygen continues to dissociate and form monatomic oxygen throughout the process.

2. The measured flame temperatures are less than 1,538°C which is the temperature at which thermal NO_x becomes significant as stated in section 5.2.2. It may be that thermal NO accounts for much less than 20% of total NO_x in this particular furnace with the majority of NO_x being produced as fuel NO_x.

8.6   Measured NO Levels During Testing

Although the attempt to predict NO was unsuccessful the actual measured amounts of NO recorded during testing did produce some promising results.

8.6.1   Secondary Air Redistribution

As can be seen from Figure 8.6 the redistribution of the secondary air to the in-service windboxes for Test 1, Test 2 and Test 3 had very little effect on NO formation. In Test 4, the over-fire air simulation, the result was a decrease in NO produced by approximately 7.5 per cent.

Secondary Air Redistribution Measured NO Levels
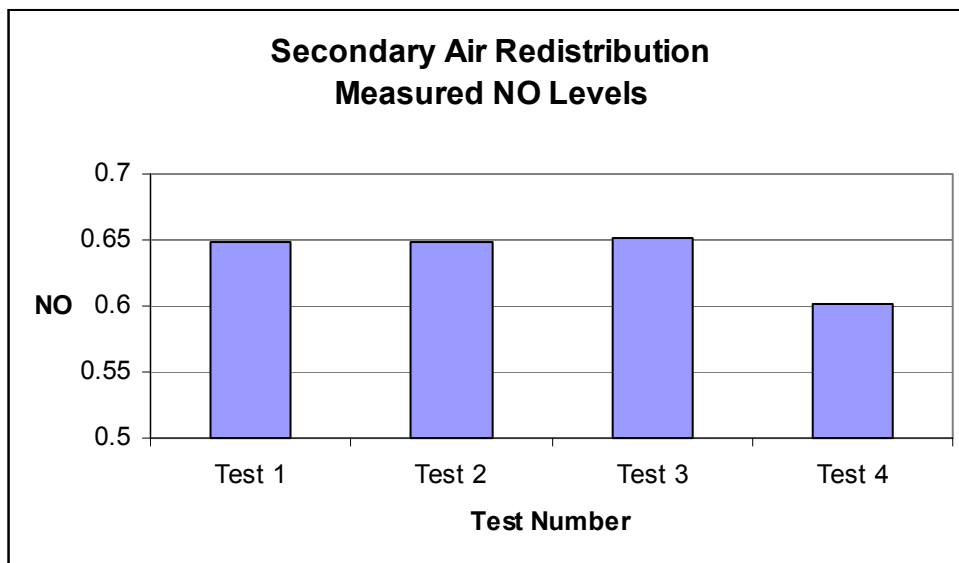
Figure 8.6 – NO Produced for Secondary Air Redistribution Tests

Figure 8.7 shows that this reduction in NO was achieved with an improvement in the furnace heat ratio when compared to the baseline test even though there was an increase in loss of ignition.

Comparison of NO Produced with Furnace Heat Ratio
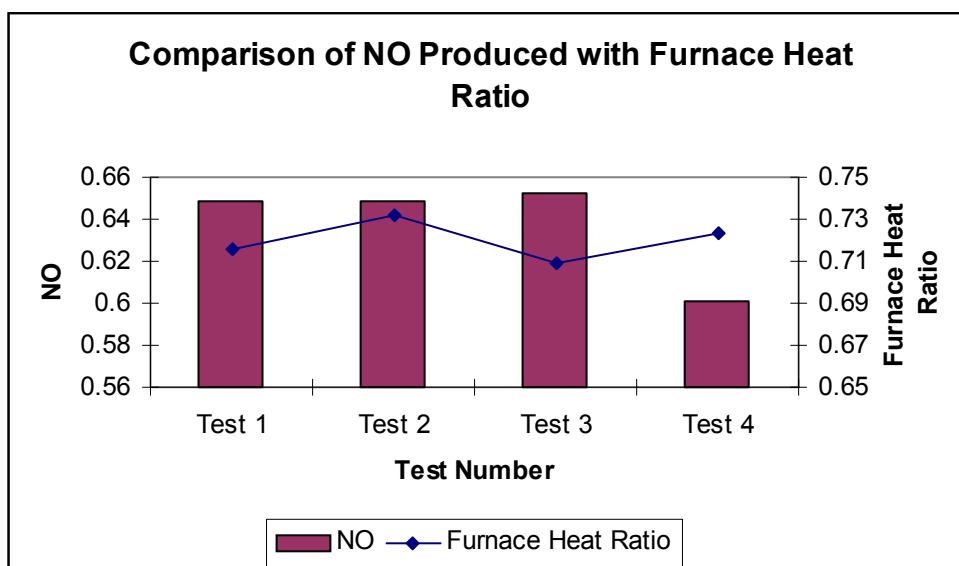
Figure 8.7 – Comparison of NO Produced with Furnace Heat Ratio for Tests 1-4

8.6.2   Excess Air Variation

The results from these series of tests were mostly as expected with increased NO as the amount of excess air increased, as is shown in Figure 8.8. The furnace heat rate improved between Test 4 and 5 before declining again as the excess air reached the high levels of Test 7.
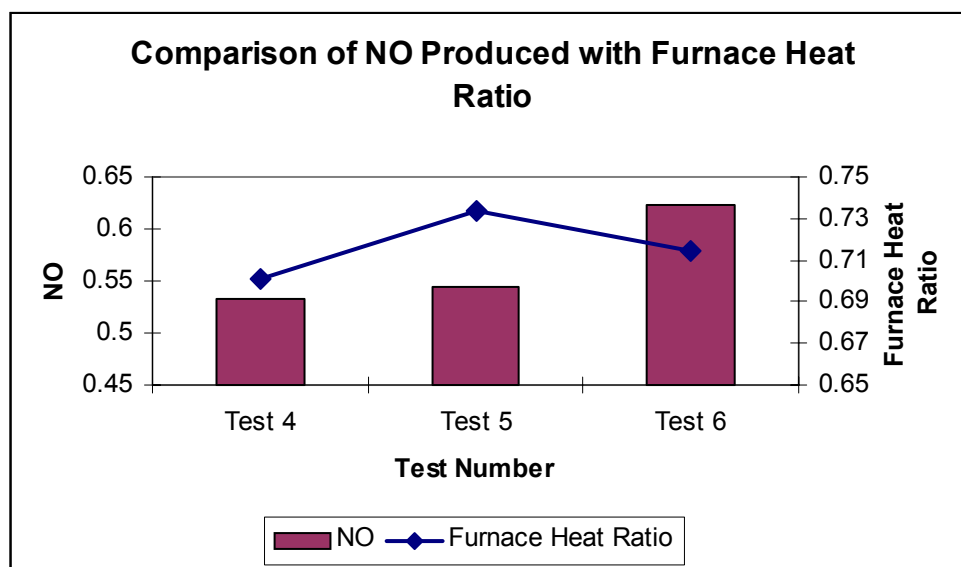
Figure 8.8 – Comparison of NO Produced with Furnace Heat Ratio for Tests 4-6

Conclusion

9

9.1   Introduction

The oxides of nitrogen (NO_x) are airborne pollutants that result from the combustion of pulverised coal. NO_x emissions contribute to acid rain and have been linked to climate change. This project was undertaken to identify operational methods that reduce the NO_x emissions whilst maintaining satisfactory plant performance. Testing was performed on a 350 MW coal fired boiler at Stanwell Power Station in Central Queensland.

9.2   Achievement of Objectives

Coal characteristics important in the combustion of pulverised coal include rank, ultimate analysis and specific energy. The sequence of processes coal particles undergo during combustion including the release of the volatile matter, the combustion of residual char and release of mineral matter were discussed.

The function of each of the boiler plant areas relevant to the project including pulverisation plant, draught plant and steam plant were discussed in detail. Limitations of the plant that affect the coal combustion process include flame stability, excess air requirements and minimum coal air mixture velocity.

The dominant NO_x formation mechanisms within the furnace are fuel NO_x and thermal NO_x. The Zeldovich mechanism and its associated rate constants describe the formation of thermal NO_x. Currently there are no theoretical methods to describe fuel NO_x formation within a coal fired furnace. The technology available to control NO_x emissions from thermal power stations include over-fire air, flue gas recirculation, combustion optimisation, advanced low NO_x burners as well as selective catalytic and selective non-catalytic reduction.

Combustion properties including equivalence ratios, initial flame temperature approximations, residence time approximations and mole and mass fractions were developed to describe the combustion process within the furnace. These properties

were to be used in the development of a thermal NO_x prediction model. However, the model for thermal NO_x did not adequately describe what was occurring in the furnace and it was considered futile to pursue a suitable model in a complex and uncontrollable plant by theoretical means. This is reiterated by the fact that it is impossible to distinguish the proportion of NO_x produced by either of the two dominant mechanisms.

A series of tests were undertaken to examine the effect on NO_x formation and boiler performance by varying operational parameters such as secondary air distribution and excess oxygen levels. The secondary air redistribution tests did not produce any positive results with regard to NO_x reduction whilst the excess air tests produced the expected result of NO_x emissions increasing as excess air increased. The simulated over-fire air test (Test 4) produced positive results with NO_x emissions reduced by approximately 7.5% of baseline levels whilst achieving excellent furnace heat pickup.

9.3 Further Work

There is still a great deal of testing that would need to be undertaken before the optimum operational positions of the windbox dampers controlling the distribution of secondary air can be implemented. It would be a worthwhile exercise to traverse test the windbox ducts on each burner level with the dampers at different positions to determine the exact amount of secondary air being delivered to each of the burner rows. Although the simulated over-fire air test did achieve promising results there are other variables including clinker build up, flame stability and temperature distribution issues that would require investigation before any permanent changes to operational philosophy would be considered.

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Appendix A

University of Southern Queensland

FACULTY OF ENGINEERING AND SURVEYING

ENG 4111/4112 Research Project
PROJECT SPECIFICATION

FOR: **ANTHONY GOODGER**

TOPIC: THE FORMATION OF NITROGEN OXIDES IN A
PULVERISED COAL BOILER

SUPERVISORS: Dr Dr Ruth Mossad and Dr David Buttsworth

PROJECT AIM: This project seeks to identify, understand and control the
mechanisms responsible for the development of nitrogen oxides
(NO_x) in a pulverised coal fired boiler.

PROGRAMME: **Issue B, 26 October 2004**

1. Research the mechanisms responsible for NO_x production.

2. Research the environmental effects of NO_x production and Australia's current
position with respect to the Kyoto agreement.

3. Develop engineering models to describe important combustion properties in a
pulverised coal fired boiler.

4. Develop understanding of boiler plant operation, fluid mechanics and heat transfer.

5. Establish testing regime under varying operational conditions to monitor NO_x
production, thermal efficiency and the parameters that affect them.

6. Compare test results with theoretical values.

As time permits:

7. Suggest operational changes to reduce NO_x production whilst still maintaining
acceptable efficiency.

AGREEED:

_____ (Student) _____ (Supervisor)

27 / 10 / 2004   ___ / ___ / ___

Appendix B

Calculation of Flame Temperature

The following scripts Flame_Temp2.m and Flame_Splines2.m are Matlab scripts developed to calculate the flame temperature of pulverised coal. They follow closely methods described by Field, Gill, Morgan and Hawkley, 1967.

```
%Script to calculate flame temperature closely following methods
%detailed in "Combustion of Pulverised Coal" by Field et al (1967)
%Written by Anthony Goodger 2004

%Inputs
%Carbon,Hydrogen,Nitrogen,Oxygen,Sulphur expressed
%as a percentage of dry ash free coal
%Moisture content expressed as a percentage of wet but ash free coal
%Gross calorific value expressed in cal/g for daf coal
%ratio of O2 actually supplied to the fuel to the quantity required
to
%burn C,H & S to CO2,H2O & SO2 (additional to O2 in fuel)

%Output
%Flame temperature in Kelvin

per=input('Enter C,H,O,N,S as percentage of daf coal:')

airflow=input('Enter total (FD) air flow:')
coalflow=input('Enter total fuel flow:')

%allow for air heater loss and seal air fans
airflow=(0.95*airflow+3.87)*0.23;

%Calculation of stoichiometric air requirement
f_denom=(per(1)*0.0267+per(2)*0.0794+((per(5)-
per(3))/100))*coalflow;
f0=airflow./f_denom;

l=per(1)/12;
m=per(2);
p=per(3)/16;
q=per(4)/14;
r=per(5)/32;
M=input('Enter moisture content as % of wet but ash free coal:');
k=100*M/(18*(100-M));
alpha=f0*(2*l+0.5*m+2*r-p);
beta=68.7*alpha+18*k+100;

%Determine C,H & N to O ratios
den=alpha+p+k;
COrat=l/den;
HOrat=(m+2*k)/den;
```

```matlab
NOrat=(3.76*alpha+q)/den;

%Determine enthalpy of product gas
%Heat of formation of fuel
%Determine CV from method described in Juniper 1999
CVMJ=0.366*per(1)+1.212*per(2)-0.083*per(3)-1.786;
%Convert MJ/kg to cal/g
CV=CVMJ*238.85;
hfuel=100*CV-94052*l-34159*m; %cal/mole fuel

%Equations to determine value of f from Fig C.1
x=COrat;
y=HOrat;
xl=[0.363 0.394 0.423 0.443 0.467 0.492];
yl=0.368*xl+0.0025;
xu=[0.311 0.337 0.357 0.371 0.39 0.409];
yu=1.206*xu-0.0002;
m=(yu-yl)./(xu-xl);
c=yu-m.*xu;
eq1=m(1)*x+c(1);
eq2=m(2)*x+c(2);
eq3=m(3)*x+c(3);
eq4=m(4)*x+c(4);
eq5=m(5)*x+c(5);
eq6=m(6)*x+c(6);

if y>eq1&y<eq2
    f=1.2
elseif y>eq2&y<eq3
    f=1.1
elseif y>eq3&y<eq4
    f=1.05
elseif y>eq4&y<eq5
    f=1
elseif y>eq5&y<eq6
    f=0.95
else
    f=0.9
end

%Enthalpy of preheat air (cal/mole)
%h_pre=input('Temp of preheat air:100, 200 or 300 degrees C:')
%Enter values for test runs
h_pre=300;
switch h_pre
case 100
    h_p=523.6;
case 200
    h_p=1228;
case 300
    h_p=1944.3;
end
%Heat Loss- assume 15%
hl=100*CV/6.67;
%Enthalpy of product gas
h_gas=hfuel+h_p-hl;

%Divide by beta to obtain enthalpy of product gas in cal/g
h_gas2=h_gas/beta;
[TT]=Flame_splines2(COrat,h_gas2,f);
```

```matlab
Temperature=round(TT)

%Apparent NO correction from Fig C.2
x_low=[0.322 0.347 0.361 0.377 0.395];
y_low=-1.096.*x_low+3.73;
x_up=[0.356 0.389 0.409 0.428 0.449];
y_up=-0.086.*x_up+3.77;
m=(y_up-y_low)./(x_up-x_low);
c=y_low-m.*x_low;

switch f
    case 1.2
        if COrat<x_up(1)
            NO_app=m(1).*COrat+c(1);
        else
            NO_app=-0.086.*COrat+3.77;
        end
     case 1.1
        if COrat<x_up(2)
            NO_app=m(2).*COrat+c(2);
        else
            NO_app=-0.086.*COrat+3.77;
        end
    case 1.05
        if COrat<x_up(3)
            NO_app=m(3).*COrat+c(3);
        else
            NO_app=-0.086.*COrat+3.77;
        end
    case 1
        if COrat<x_up(4)
            NO_app=m(4).*COrat+c(4);
        else
            NO_app=-0.086.*COrat+3.77;
        end
     case 0.95
        if COrat<x_up(5)
            NO_app=m(5).*COrat+c(5);
        else
            NO_app=-0.086.*COrat+3.77;
        end
end

%determine deltaNO
deltaNO=NOrat-NO_app;

%figure C.3 splines
T_2=1400:200:3000;
switch f
    case 0.95
        delE_delNO=[129 128 127 126 125 120 110 92 73];
        val=spline(T_2,delE_delNO,TT);
    case 1
        delE_delNO=[132 131 130 128 125 119 108 90 70];
        val=spline(T_2,delE_delNO,TT);
    case 1.05
        delE_delNO=[127 126 125 124 121 117 105 88 69];
        val=spline(T_2,delE_delNO,TT);
    case 1.1
        delE_delNO=[122 121 120.5 119 117 113 102 84 67];
        val=spline(T_2,delE_delNO,TT);
```

```matlab
    case 1.2
        T_2=1400:200:2600;
        delE_delNO=[112 111 109 108 106 103 95];
        val=spline(T_2,delE_delNO,TT);
end

%correct enthalpy value
enth_corr=deltaNO*val+h_gas2;
h_gas2=enth_corr;
[TT]=Flame_splines2(COrat,h_gas2,f);

Corrected_Temperature=round(TT)
```

```matlab
enth_corr=deltaNO*val+h_gas2;
```

```matlab
%Cubic spline script to calculate flame temperature from graphs
%detailed in "Combustion of Pulverised Coal" by Field et al (1967)
%Written by Anthony Goodger 2004


%Cubic splines to solve for temperature
function[TT]=Flame_splines2(COrat,h_gas2,f)

T=[1400:200:2800];
switch f

case 0.9;
    if COrat>0.401&COrat<0.4300
        H=[-381 -317 -250 -85 -111 -11 129 296];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.4301&COrat<0.4500
        H=[-355 -288 -225 -159 -87 7 148 318];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.4501&COrat<0.4700
        H=[-329 -267 -205 -137 -63 30 163 326];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.4701&COrat<0.5200
        H=[-307 -244 -181 -115 -44 48 178 333];
        TT=spline(H,T,h_gas2);
    end

case 0.95;
    if COrat>0.3901&COrat<0.4100
        H=[-390 -330 -265 -197 -115 -7 140 317];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.4101&COrat<0.4300
        H=[-362 -307 -241 -172 -86 17 155 322];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.4301&COrat<0.4500
        H=[-338 -282 -218 -149 -69 35 172 328];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.4501&COrat<0.4700
        H=[-320 -262 -200 -135 -55 48 179 345];
        TT=spline(H,T,h_gas2);
    end

case 1;
    if COrat>0.3701&COrat<0.3900
        H=[-413 -343 -273 -200 -110 0 143 316];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.3901&COrat<0.4100
        H=[-380 -317 -250 -173 -87 23 163 330];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.4101&COrat<0.4300
        H=[-357 -290 -223 -150 -67 43 180 350];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.4301&COrat<0.4500
        H=[-333 -273 -206 -133 -46 63 197 350];
        TT=spline(H,T,h_gas2);
    end

case 1.05;
    if COrat>0.3501&COrat<0.3700
        H=[-383 -323 -257 -180 -93 13 157 333];
        TT=spline(H,T,h_gas2);
    elseif COrat>0.3701&COrat<0.3900
```

```
      H=[-353 -293 -230 -157 -70 37 180 343];
      TT=spline(H,T,h_gas2);
   elseif COrat>0.3901&COrat<0.4100
      H=[-327 -270 -207 -133 -43 63 200 353];
      TT=spline(H,T,h_gas2);
   elseif COrat>0.4101&COrat<0.4300
      H=[-310 -250 -190 -120 -30 77 213 363];
      TT=spline(H,T,h_gas2);
   end

case 1.1;
   if COrat>0.3401&COrat<0.3550
      H=[-348 -290 -219 -148 -68 35 174 345];
      TT=spline(H,T,h_gas2);
   elseif COrat>0.3561&COrat<0.3700
      H=[-329 -270 -203 -132 -52 55 187 358];
      TT=spline(H,T,h_gas2);
   elseif COrat>0.3701&COrat<0.3900
      H=[-303 -248 -177 -106 -29 74 206 371];
      TT=spline(H,T,h_gas2);
   elseif COrat>0.3901&COrat<0.4300
      H=[-281 -225 -158 -90 -13 87 223 380];
      TT=spline(H,T,h_gas2);
   end

case 1.2;
   T=[1400:200:2600]
   if COrat>0.2901&COrat<0.3100
      H=[-306 -243 -176 -106 -23 73 203];
      TT=spline(H,T,h_gas2)
   elseif COrat>0.3101&COrat<0.3300
      H=[-273 -210 -146 -77 3 100 227];
      TT=spline(H,T,h_gas2)
   elseif COrat>0.3301&COrat<0.3600
      H=[-240 -177 -113 -47 33 120 257];
      TT=spline(H,T,h_gas2)
   end
   end
```

Appendix C

Periodic Table

Periodic Table of Elements

Appendix D

Coal Analysis and Test Data

	Test 1	Test 2	Test 3	Test 4	Test 5 3% Excess O2	Test 6 4% Excess O2	Test 7 5.5% Excess O2
	Baseline 1	Square	Inverted	OFA			
Moisture Content (%ar)	7.5	7.5	7.6	7.4	7.9	8.3	8.2
Ash Content (%ad)	13.1	15.2	13.8	16.1	18.2	15.6	18.5
Carbon Content (%daf)	88	87.9	88	87.3	89	88.1	87.8
Hydrogen Content (%daf)	4.91	5.02	5.01	4.96	4.74	4.89	4.86
Nitrogen Content (%daf)	1.88	1.86	1.9	1.91	1.83	1.91	1.88
Sulphur Content (%daf)	0.65	0.56	0.66	0.77	0.73	0.68	0.77
Oxygen Content (%daf)	4.53	4.68	4.47	5.02	3.66	4.38	4.71
Reactant Mass (kg/kg coal)	0.804	0.784	0.796	0.777	0.753	0.774	0.748
Carbon (kg/kg coal)	0.707	0.689	0.701	0.678	0.671	0.682	0.657
Hydrogen (kg/kg coal)	0.039	0.039	0.040	0.039	0.036	0.038	0.036
Nitrogen (kg/kg coal)	0.015	0.015	0.015	0.015	0.014	0.015	0.014
Sulphur (kg/kg coal)	0.005	0.004	0.005	0.006	0.005	0.005	0.006
Oxygen (kg/kg coal)	0.036	0.037	0.036	0.039	0.028	0.034	0.035
Stoichiometric O2	2.171	2.121	2.158	2.084	2.052	2.092	2.013
Stoichiometric Air	9.357	9.143	9.301	8.982	8.844	9.019	8.677
Forced Draft Flow (kg/s)	306	298	306	303	274	294	318
Combustion Air (kg/s)	294.6	287.0	294.6	291.7	264.2	283.2	306.0
Coal Flow Rate (kg/s)	25.9	26	25.9	26	26.4	26.4	26.4
Equivalence Ratio	0.823	0.828	0.818	0.801	0.884	0.841	0.749
Excess Air	21.548	20.713	22.276	24.914	13.149	18.929	33.564
Excess O2	4.999	4.806	5.168	5.780	3.051	4.392	7.787
LOI	1.7	3.2	0.8	5.9	7.3	10.9	6.1
NO Level	0.649	0.649	0.652	0.601	0.532	0.545	0.624
MW carbon	12.011	12.011	12.011	12.011	12.011	12.011	12.011
MW hydrogen	1.00797	1.00797	1.00797	1.00797	1.00797	1.00797	1.00797
MW nitrogen	14.007	14.007	14.007	14.007	14.007	14.007	14.007
MW sulphur	32.064	32.064	32.064	32.064	32.064	32.064	32.064
MW oxygen	15.9994	15.9994	15.9994	15.9994	15.9994	15.9994	15.9994

	Test 1	Test 2	Test 3	Test 4	Test 5 3% Excess O2	Test 6 4% Excess O2	Test 7 5.5% Excess O2
	Baseline 1	Square	Inverted	OFA			
MW mix	9.8457	10.0057	9.8606	10.1644	10.6235	10.2403	10.6212
Mole Fractions							
Carbon	0.5798	0.5744	0.5754	0.5740	0.5930	0.5813	0.5809
Hydrogen	0.3855	0.3909	0.3904	0.3886	0.3764	0.3845	0.3831
Nitrogen	0.0106	0.0104	0.0107	0.0108	0.0105	0.0108	0.0107
Sulphur	0.0016	0.0014	0.0016	0.0019	0.0018	0.0017	0.0019
Oxygen	0.0224	0.0230	0.0219	0.0248	0.0183	0.0217	0.0234
Atom Ratios							
Carbon	0.5798	0.5744	0.5754	0.5740	0.5930	0.5813	0.5809
Hydrogen	0.7710	0.7818	0.7807	0.7772	0.7527	0.7690	0.7663
Nitrogen	0.0212	0.0208	0.0213	0.0215	0.0209	0.0216	0.0213
Sulphur	0.0016	0.0014	0.0016	0.0019	0.0018	0.0017	0.0019
Oxygen	0.0448	0.0459	0.0439	0.0496	0.0366	0.0434	0.0468
Carbon	579.8	574.4	575.4	574.0	593.0	581.3	580.9
Hydrogen	771.0	781.8	780.7	777.2	752.7	769.0	766.3
Nitrogen	21.2	20.8	21.3	21.5	20.9	21.6	21.3
Sulphur	1.6	1.4	1.6	1.9	1.8	1.7	1.9
Oxygen	44.8	45.9	43.9	49.6	36.6	43.4	46.8
Flame Temp by Field (K)	2177	2094	2175	2167	1950	2086	2108
Specific Energy (MJ/kg) Dulong Formula	36.10	36.19	36.25	35.86	36.35	36.13	35.94
Specific Energy (MJ/kg)	36.00	36.08	36.12	35.76	36.23	36.02	35.85
Specific Energy (cal/g)	8597.87	8617.99	8628.00	8541.43	8653.32	8603.79	8562.34