

Optimization of Combustion in Pulverised Coal Fired Boiler

By

Tharayil James Joseph

13MMET21



DEPARTMENT OF MECHANICAL ENGINEERING
INSTITUTE OF TECHNOLOGY
NIRMA UNIVERSITY
AHMEDABAD-382481

May 2015

Optimization of Combustion in Pulverised Coal Fired Boiler

Major Project Report

Part - II

Submitted in partial fulfillment of the requirements

For the Degree of

Master of Technology in Mechanical Engineering

(Thermal Engineering)

By

Tharayil James Joseph

(13MMET21)

Guided By

Prof. B. A. Shah

Mr. Dinkar Jethva



DEPARTMENT OF MECHANICAL ENGINEERING
INSTITUTE OF TECHNOLOGY

NIRMA UNIVERSITY
AHMEDABAD-382481

May 2015

Declaration

This is to certify that

1. The thesis comprises of my original work towards the degree of Master of Technology in Mechanical Engineering (Thermal Engineering) at Nirma University and has not been submitted elsewhere for a degree.
2. Due acknowledgment has been made in the text to all other material used.

Tharayil James Joseph

13MMET21

Undertaking for Originality of the Work

I, Tharayil James Joseph, Roll. No. 13MMET21, give undertaking that the Major Project Part-II entitled “Optimization of Combustion in Pulverised Coal Fired Boiler” submitted by me, towards the partial fulfillment of the requirements for the degree of Master of Technology in Mechanical Engineering (Thermal) of Nirma University, Ahmedabad, is the original work carried out by me and I give assurance that no attempt of plagiarism has been made. I understand that in the event of any similarity found subsequently with any published work or any dissertation work elsewhere; it will result in severe disciplinary action.

Signature of Student

Endorsed by
(Signature of Guide)

Date: 15-05-2015

Place:Ahmedabad

Certificate

This is to certify that the Major Project Part-II Report entitled “**Optimization of Combustion in Pulverised Coal Fired Boiler**” submitted by **Mr Tharayil James Joseph (13MMET21)**, towards the partial fulfillment of the requirements for the award of Degree of Master of Technology in Mechanical Engineering (Thermal Engineering) of Institute of Technology, Nirma University, Ahmedabad is the record of work carried out by him under our supervision and guidance. In our opinion, the submitted work has reached a level required for being accepted for examination. The result embodied in this major project, to the best of our knowledge, has not been submitted to any other University or Institution for award of any degree.

Prof. B. A. Shah,
Internal Guide and Assistant Professor,
Department of Mechanical Engineering,
Institute of Technology,
Nirma University,
Ahmedabad.

Mr Dinkar Jethva,
External Guide and Executive Engineer,
Gujarat State Electricity Corporation Ltd.
Thermal Power Station,
Wanakbori-388239,
Gujarat.

Dr R N Patel
Professor and Head,
Department of Mechanical Engineering,
Institute of Technology,
Nirma University,
Ahmedabad

Dr K Kotecha
Director,
Institute of Technology,
Nirma University,
Ahmedabad

Acknowledgments

I take this opportunity to express deep sense of gratitude and sincere thanks for the invaluable assistance that I have received from my honorable and learned guide **Prof. B. A. Shah** (Assistant Professor, Mechanical Engineering Department, IT, NU). He is the constant source of encouragement and momentum that any intricacy becomes simple. I gained a lot of invaluable guidance and prompt suggestions from him during my thesis work. I remain indebted of him forever and I take pride to work under him. My sincere thanks and due respect to my industry guide **Mr. Dinkar Jethva** for his constant cooperation, valuable suggestions and guidance throughout this dissertation work. I am very thankful to **Dr. K. Kotecha** (Director, IT, NU) and to **Dr. R. N. Patel** (Head of Department, IT, NU) and all the faculty members of Mechanical Engineering Department who have directly or indirectly helped me during this dissertation work. My special thanks to my friends of M.Tech Thermal Engineering. At the end I am thankful to Almighty God, my family, and colleagues who have directly or indirectly helped me during this dissertation work and for their encouragement.

Tharayil James Joseph

Abstract

The demand of electricity is increasing nowadays and has raised the necessity of improved power generation technologies, especially in developing countries like India. Reduction of emissions of greenhouse gases is the need of hour and it could be achieved considerably by improving the efficiency of existing coal fired plants. Operation of non optimized boiler can lead to reduced boiler efficiency, increased excess air requirements, delayed combustion, increased heat rate, high CO and NO_x emissions and many other. Optimization of combustion in pulverised coal fired boiler is very important today for every thermal power plant. The objective of this work is to optimize the combustion in pulverised coal fired boiler in order to improve the boiler efficiency and thereby to reduce the heat losses occurring in the boiler such as dry flue gas loss etc. The combustion in pulverised coal fired boiler is affected by quality of coal, pulverised coal fineness, burner tilting angle, air fuel ratio, slagging and NO_x formation. Clean air and dirty air test for bowl mill to balance coal supply at four corners of boiler furnace of unit 5 have been carried out. Then, optimization of combustion have been carried out with the help of secondary air dampers which resulted into improvement in boiler efficiency from 84.52% to 85.43% and reduction in heat losses from 15.47% to 14.56%. Also, optimum position of burner tilting angle based upon economic analysis of reduction in R.H spray have been carried out. At last, the exergy analysis of combustion process have been carried out which resulted into rational efficiency of boiler as 40.5% and combustion efficiency as 86.3%.

Contents

Declaration	ii
Certificate	iv
Acknowledgments	v
Abstract	vi
Table of Contents	ix
List of Figures	x
List of Tables	xi
Nomenclature	xiii
1 Introduction	1
1.1 Steam Generator	1
1.2 About Wanakbori Thermal Power Station (WTPS)	2
1.3 Motivation	2
1.4 Objective of the Project	3
2 Literature Review	4
2.1 Combustion	4
2.1.1 Stoichiometric Air	5
2.1.2 Control of Excess Air	6
2.2 Pulverised Coal Fired Boiler	8
2.3 Burner Arrangement	11
2.3.1 Tangential firing	11
2.4 Secondary Air Damper Control (SADC)	12
2.5 Terminology involved in combustion	13

2.6	Factors affecting the combustion	14
2.7	Combustion Behaviour	15
2.8	Boiler Performance Monitoring Techniques	15
2.8.1	On-Line Monitoring Technique	15
2.8.2	Off-Line Monitoring Technique	18
2.9	Coal Analysis	19
2.9.1	Proximate & Ultimate Analysis	20
2.10	Bomb Calorimeter	21
2.11	Calculation of air required for complete combustion	22
2.12	Recent Work	22
2.12.1	Experimental and Theoretical Work	22
2.12.2	CFD Work	25
2.13	Conclusion of Literature Review	25
3	Optimization of Combustion	27
3.1	Pulverised Coal Flow Balancing	27
3.1.1	Clean Air Flow Test	27
3.1.2	Dirty Air Flow Test	30
3.2	Secondary Air Damper Control	34
3.3	Different losses associated with excess air	35
3.4	Analysis of Optimum excess air	35
3.4.1	Dry flue gas loss	36
3.4.2	Incomplete combustion loss	36
3.4.3	Combined heat loss	37
3.5	Boiler efficiency before correcting damper position	38
3.5.1	Coal analysis and other operating parameters	38
3.5.2	Heat losses and Boiler Efficiency	39
3.5.3	Correction in air supplied	39
3.6	Boiler efficiency after correcting damper position.	40
3.6.1	Coal analysis and other operating parameters	40
3.6.2	Heat losses and Boiler efficiency	41
3.7	Results and Discussion	42
3.7.1	For clean air test	42
3.7.2	For dirty air test	43
3.7.3	For secondary air damper	46

4	Economic Analysis of Reheat Spray & Exergy Analysis of Combustion	47
4.1	Reheat steam temperature control	47
4.2	Temperature control using burner tilting	48
4.3	Economic analysis of reheat spray	49
4.4	Exergy	51
4.5	Forms of exergy	51
4.6	Chemical processes including combustion	52
4.6.1	Chemical components of exergy	54
4.6.2	Physical components of exergy	54
4.7	Exergy Analysis	55
5	Conclusion and Future Scope of Work	60
5.1	Conclusion	60
5.2	Future Scope of Work	60
	Bibliography	61

List of Figures

2.1	CO ₂ Variation in flue gas with fuels and excess air[2]	7
2.2	O ₂ Variation in flue gas with excess air[2]	7
2.3	Optimum excess air for maximum combustion efficiency[2]	7
2.4	General arrangement of pulverised coal fired boiler[2]	9
2.5	Equipments for Central and Unit System[1]	10
2.6	Tangential firing[1]	12
2.7	Damper Arrangement[1]	13
2.8	Bomb Calorimeter[3]	21
3.1	Clean Air Test[13]	28
3.2	Dirty Air Test[13]	30
3.3	Damper arrangement[16]	34
3.4	Dry flue gas loss vs Excess air	36
3.5	Incomplete combustion loss vs Excess air	37
3.6	Combined heat loss vs Excess air	38
3.7	Clean Air Flow vs Corners	42
3.8	Dirty air flow vs Corners	44
3.9	Fuel flow vs Corners	44
3.10	A/F Ratio vs Corners	45
4.1	Burner tilting positions[16]	49
4.2	% Economic gain at different burner tilting position	50
4.3	Control region of reacting open system[21]	53
4.4	Coal fired plant[21]	55

List of Tables

2.1	Technical Specifications of Boiler used at Stage-II of WTPS[3]	8
2.2	Colour of the flame versus temperature[1]	15
2.3	Boiler data sheet	16
2.4	Coal mill data sheet	17
2.5	Boiler feed pump data	18
2.6	Coal mill data sheet	19
2.7	Different Grades of Coal[3]	20
2.8	Proximate and Ultimate Analysis	22
3.1	Clean Air Test readings	29
3.2	Dirty Air Test readings	31
3.3	Proximate and Ultimate analysis	38
3.4	Operating Parameters	39
3.5	Heat losses and Boiler efficiency before correcting damper position	39
3.6	Secondary air flow through FAD	40
3.7	Auxiliary air damper correction	40
3.8	Proximate and Ultimate analysis	40
3.9	Operating parameters	41
3.10	Heat losses and Boiler efficiency after correcting damper position	41
3.11	Clean air test showing velocity and airflow at four corners.	42
3.12	Observation of deviations in clean air test	42
3.13	Dirty air test	43
3.14	Observation of deviations in dirty air test	45
4.1	Effect of Reheat spray in burner tilting	49
4.2	Composition of Bituminous by mass	56
4.3	No of moles and mole fraction of products of combustion	56
4.4	Value of \hat{C}_p^h for products of combustion.	57
4.5	Value of standard chemical exergy of product of combustion	57

4.6	Value of $\hat{C}p^\varepsilon$ for products of combustion	58
4.7	Value of $\hat{C}p^h$ for combustion products	58
4.8	Values of $\hat{C}p^\varepsilon$ for combustion products	59

Nomenclature

W_A	Actual air required, kg/kg of fuel
W_T	Theoretical air required, kg/kg of fuel.
V	Velocity, m/s
\dot{E}_k	Kinetic exergy, kJ
\dot{E}_p	Potential exergy, kJ
\dot{E}_{ph}	Physical exergy, kJ
\dot{E}_o	Chemical exergy, kJ
ε^o	Standard chemical exergy, kJ/kmol
$\hat{C}p^\varepsilon$	Mean molar isobaric exergy capacity, kJ/kmol K
$\hat{C}p^h$	Mean molar isobaric heat capacity, kJ/kmol K
Φ	Ratio of industrial fuel
n_k	Number of moles in combustion products, kmol/kg
x_k	Mole fraction in combustion products
I	Irreversibility, kJ
E	Exergy, kJ
m	Mass, kg
H, h	Enthalpy kJ, specific enthalpy kJ/kg
S, s	Entropy kJ/K, specific entropy kJ/kgK
\dot{R}	Molar (universal) gas constant, J/mol K
ϑ	Temperature on an arbitrary scale, $^{\circ}\text{C}$
Ψ	Rational or second law efficiency
η_c	Combustion efficiency

Abbreviations

WTPS	Wanakbori Thermal Power Station
PA	Primary Air
SA	Secondary Air
SH	Super Heater
RH	Re heater
PSH	Primary Super Heater
HRH	Hot Reheat
CRH	Cold Reheat
MS	Main Steam
HO	Heavy Oil
LDO	Light Diesel Oil

W_A	Actual air required, kg/kg of fuel
FO	Furnace Oil
ECO	Economiser
APH	Air Preheater
DE	Drive End
NDE	Non Drive End
FG	Flue Gas
BFP	Boiler Feed Pump
DP	Differential Pressure
RES	Radiant Energy Signal
SADC	Secondary Air Damper Control
GCV	Gross Calorific Value
DCS	Direct Control System
FAD	Fuel Air Damper
AAD	Auxiliary Air Damper
NCV	Net Calorific Value
O/L	Outlet

Subscripts

j	Reactant
k	Product
0	Environmental state
s	Steam
w	Water
f	Fuel

Chapter 1

Introduction

This chapter includes basics of steam generator, information regarding the Wanakbori power plant, motivation and objective for the study.

1.1 Steam Generator

A steam generator generates steam at the desired rate at the desired pressure and temperature by burning fuel in its furnace. Steam is mainly required for power generation, process heating and space heating purposes. The capacity of the boilers used for power generation is considerably large compared with other boilers. Due to the requirement of high efficiency, the steam for power generation is produced at high pressures and in very large quantities. They are very large in size and are of individual design depending upon the type of fuel to be used. The boilers generating steam for process heating are generally smaller in size and generate steam at a much lower pressure. They are simpler in design and are repeatedly constructed to the same design. A steam generator popularly known as boiler is a closed vessel made of high quality steel in which steam is generated from water by the application of heat. The water receives heat from the hot gases through the heating surfaces of the boiler. The hot gases are formed by burning fuel, may be coal, oil or gas. Heating surface of the boiler is that part of the boiler which is exposed to hot gases on one side and water or steam on the other side. The steam which is collected over the water surface is taken from the boiler through super heater and then suitable pipes for driving engines or turbines or for some industrial heating purpose. A boiler consists of not only the steam generator but also a number of parts to help for the safe and efficient operation of the system as a whole. These parts are called mountings and accessories.[1]

1.2 About Wanakbori Thermal Power Station (WTPS)

Wanakbori thermal power station (WTPS) is ISO 9000:2008 & 14001:2004 certified plant. WTPS is 7 km from Sevaliya railway station and 11 km from Balasinor. WTPS is adjacent to the Mahi River. Narmada main canal is also situated adjacent to WTPS.

There are total 07 units each of the capacity of 210 MW. The generation capacity of WTPS is 1470 MW. WTPS is super thermal power station of Gujarat. All the units are of BHEL make.

WTPS has three stages. Stage 1 is comprised of unit no. 1 to 3. All three units are of Russian type. Stage 2 is comprised of unit no. 4 to 6 and each unit are of German type. Stage 3 is comprised of unit no 7 and is totally computerized control.

Some information about Wanakbori Project:

Capacity : 1470 MW

Total Area : 1571 Hector

Plant Area : 626.2 Hector

Ash dyke Area : 215.7 Hector

Source of water : Mahi River

Wanakbori receives coal mainly from coal mines situated at Orissa, Madhya Pradesh, West Bengal, Andhra Pradesh, Chhattisgarh & Korea Reva mines. To unload received coal rack, WTPS has Wagon tippler house. There are total 5 no of tipplers which unloads the coal from coal rack round the clock. WTPS has unloaded record 710 nos of wagon in single day. Total 1800 MT-21000 MT of coal is consumed daily to generate power of 1470 MW.

1.3 Motivation

India is a seventh largest country and have a very large population. To maintain growth rate, rapid growth in energy sector is needed. About 69.6% of power generation comes from thermal power plants, in which 60.2% generation comes from using coal as fuel. The demand of electricity is increasing day by day and has raised the necessity of improved power generation technologies or to improve the performance of existing power plants.

Operating a boiler that is not optimized can lead to following

1. Increased levels of unburnt carbon
2. Increased excess air requirements
3. Increased nitrous oxide formation

4. Incorrect primary and secondary air to fuel ratios
5. Reduced boiler efficiency and increased heat rate
6. Increased slagging etc.

Hence, optimization of combustion is essential for thermal power plant.

1.4 Objective of the Project

The main objective of the project is to optimize combustion in such a way that it results into improvement in boiler efficiency using parameter like secondary air damper control. The study involves boiler performance testing by controlling secondary air supply using dampers and improvement in boiler efficiency and reduction in heat losses such as dry flue gas loss etc. The study also involves economics analysis of reheat spray in burner tilting and exergy analysis of combustion process.

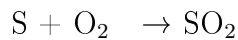
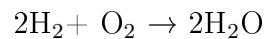
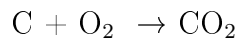
Chapter 2

Literature Review

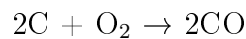
This chapter includes about basics of combustion, stoichiometric air and effects of excess air. Pulverised coal firing system, terminology involved in combustion, factors influencing combustion, behaviour of combustion and detailed study of literature available on the subject of project was conducted and has been summarized. Boiler monitoring techniques has also been discussed.

2.1 Combustion

Combustion is the high temperature oxidation of the combustible elements of a fuel with heat release. The combustible elements in coal and fuel oil are carbon, hydrogen and sulphur. The basic chemical equations for complete combustion are



When insufficient oxygen is present, the carbon will be burned incompletely with the formation of carbon monoxide.



In order to burn a fuel completely, four basic conditions must be fulfilled:

1. Supply enough air for complete combustion of fuel.
2. Secure enough turbulence for thorough mixing of fuel and air.
3. Maintain a furnace temperature high enough to ignite the incoming fuel air mixture.
4. Provide a furnace volume large enough to allow time for combustion to be completed.

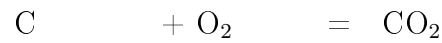
Apart from adequate air supply, the three T's, viz., time, temperature and turbulence have to be kept in mind while designing a furnace. Combustion may be said to hinge upon the word MATT- M is for mixture (turbulence), so that the fuel molecules meet the oxygen molecules, A is for the proper air-fuel ratio in order to support combustion, one T is for temperature, and the other T is for time. Since the complete mixing of the fuel and air is virtually impossible, excess air must be supplied to ensure complete combustion.[2]

2.1.1 Stoichiometric Air

The ultimate analysis of the fuel is given by

$$C + H + O + N + S + M + A = 1.0$$

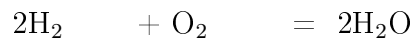
Oxygen needed for the oxidation processes can be calculated as follows:



$$12 \text{ kg} \quad 32 \text{ kg} \quad 44 \text{ kg}$$

$$1 \text{ kg} \quad 2.67 \text{ kg} \quad 3.67 \text{ kg}$$

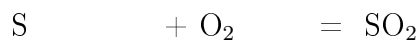
$$C \text{ kg} \quad 2.67C \text{ kg} \quad 3.67C \text{ kg}$$



$$4 \text{ kg} \quad 32 \text{ kg} \quad 36 \text{ kg}$$

$$1 \text{ kg} \quad 8 \text{ kg} \quad 9 \text{ kg}$$

$$H \text{ kg} \quad 8 H \text{ kg} \quad 9 H \text{ kg}$$



$$32 \text{ kg} \quad 32 \text{ kg} \quad 64 \text{ kg}$$

$$1 \text{ kg} \quad 1 \text{ kg} \quad 2 \text{ kg}$$

$$S \text{ kg} \quad S \text{ kg} \quad 2S \text{ kg}$$

Oxygen required for complete combustion of 1 kg fuel is

$$W_{O_2} = 2.67C + 8H + S - O$$

Where O is the oxygen in the fuel, C is the carbon content, H is hydrogen and S is sulphur.

Air contains 23.2% oxygen by mass. Therefore theoretically air required for complete combustion of 1 kg of fuel is

$$W_T = \frac{W_{O_2}}{0.232} = \frac{2.67}{0.232}C + \frac{8}{0.232}\left(H - \frac{O}{8}\right) + \frac{1}{0.232}S$$

$$W_T = 11.5C + 34.5\left(H - \frac{O}{8}\right) + 4.3S$$

where C, H, O & S are the mass fractions of carbon, hydrogen, oxygen & sulphur in the fuel.

Complete Combustion of fuel cannot be achieved if only the theoretical or stoichiometric air is supplied. Excess air is always needed for complete combustion. It is expressed as a percentage or by the use of dilute coefficient. The percent excess air supplied air is

$$\% \text{ excess air} = \frac{W_A - W_T}{W_T} \times 100$$

where W_A is actual amount of air supplied for complete combustion of 1 kg of fuel.

The dilution coefficient, d, is given by

$$d = \frac{W_A}{W_T}$$

The percentage of excess air varies between 15 and 30% for most large utility boilers.

2.1.2 Control of Excess Air

Proper control of the right amount of excess air maintains optimum combustion efficiency. Amounts of CO_2 and O_2 in combustion gases are indexes of excess air. The desirable CO_2 level depends on the fuel and the optimum excess air for the furnace. Desirable O_2 values depend much less on the type of fuel. This makes O_2 measurement the preferred method for combustion control. If the measured O_2 content is more than that desired, the air supply is to be reduced. If the O_2 measured is less than that desired, air supply is to be increased.

Boiler losses are estimated as outlined in different outputs in Figure 2.3. The excess air is then adjusted by controlling air supply to show the optimum value of excess air for best combustion efficiency is then ascertained.

The excess air can also be determined using the following relation

$$\% \text{ excess air} = \frac{O_2 - 0.5CO}{0.264N_2 - (O_2 - 0.5CO)} \times 100$$

where O_2 , CO and N_2 are the volumetric percentages in the dry flue gas.

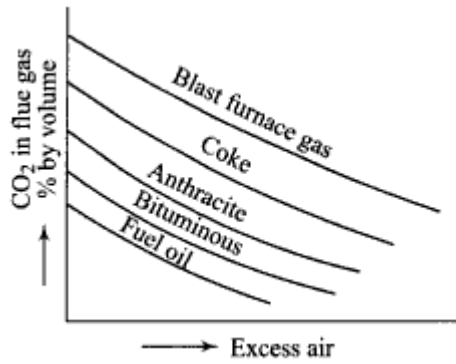


Figure 2.1: CO₂ Variation in flue gas with fuels and excess air[2]

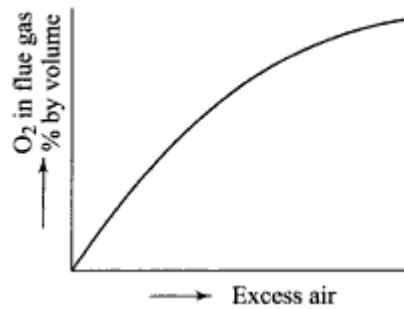


Figure 2.2: O₂ Variation in flue gas with excess air[2]

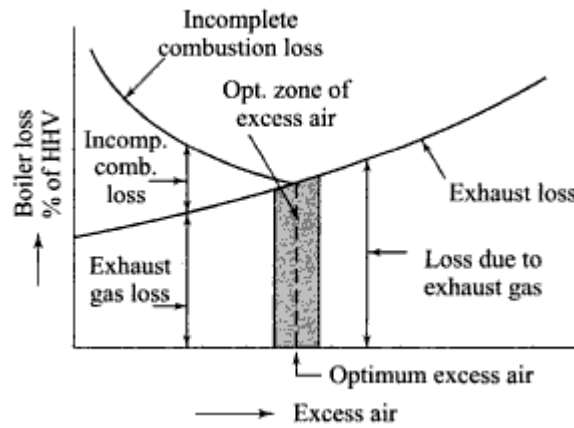


Figure 2.3: Optimum excess air for maximum combustion efficiency[2]

2.2 Pulverised Coal Fired Boiler

The first commercial application of pulverized coal firing for steam generation was made in the early 1920s. Since then it has become almost universal in central utility stations using coal as fuel. A pulverised coal-fired boiler is an industrial boiler used in most of the thermal power plants in operation nowadays. It generates thermal energy by burning pulverised coal that is blown into the firebox. The basic idea of firing system using pulverised fuel is to use the whole volume of the furnace for the combustion of solid fuels. Coal is ground to the size of a fine grain, mixed with air and burned in the flue gas flow. Coal contains mineral matter which is converted to ash during combustion. The ash is removed as bottom ash and fly ash. The bottom ash is removed at the furnace bottom. This type of boiler dominates the electric power industry, providing steam to drive large turbines. The general arrangement of pulverised coal fired boiler is shown in Figure 2.4.[2]

Technical specification of pulverised coal fired boiler and its accessories are given in Table 2.1.

Table 2.1: Technical Specifications of Boiler used at Stage-II of WTPS[3]

Boiler Type	Tangentially coal fired,water tube,natural circulation
Fuel	Indian Bituminous Coal
Generation Capacity	Upto 210 MW
Furnace Type	Fusion Welded Panels
Low Temperature Superheater	425 °C
Platen Superheater	515 °C
Final Superheater	540 °C
Reheater	300 to 540 °C
Economizer	245 to 280 °C
Air Preheater	300 to 336 °C

The concept of burning coal that has been pulverized into a fine powder comes from the belief that if the coal is made fine enough, it will burn almost as easily and efficiently as a gas. The feeding rate of coal according to the boiler demand and the amount of air available for drying and transporting the pulverized coal fuel is controlled by computers. Pieces of coal are crushed between balls or cylindrical rollers that move between two tracks or "races." The raw coal is then fed into the pulveriser along with air heated to about 330 °C from the boiler. As the coal gets crushed by the rolling action, the hot air dries it and blows the usable fine coal powder out to be used as fuel. The powdered coal from the pulveriser is directly blown to a burner in the boiler.

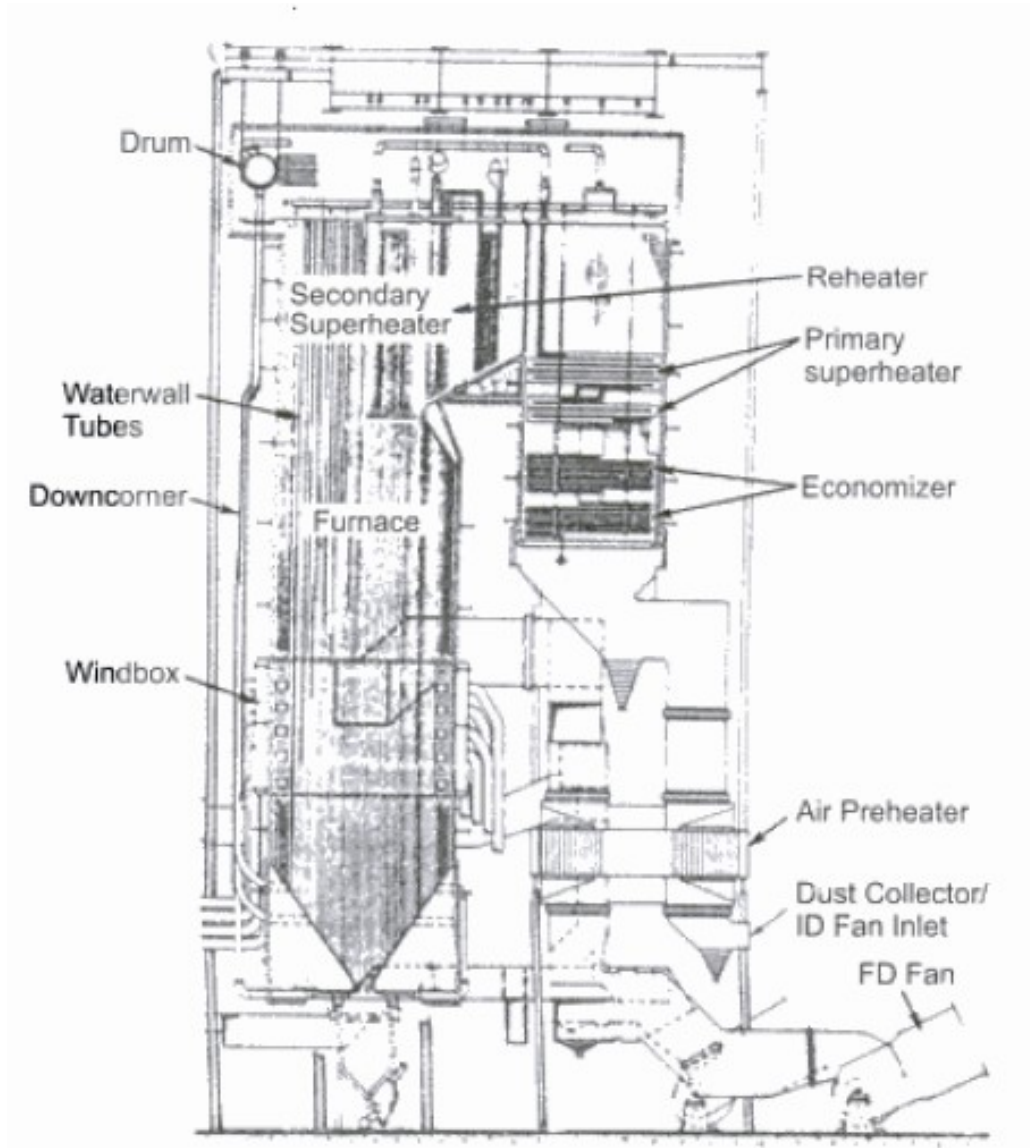


Figure 2.4: General arrangement of pulverised coal fired boiler[2]

To burn pulverized coal successfully, the following two conditions must be satisfied:

- 1) Large quantities of very fine particles of coal, usually those that would pass a 200 mesh sieve must exist to ensure ready ignition because of their large surface-to volume ratio.
- 2) Minimum quantity of coarser particles should be present since these coarser particles cause slagging and reduce combustion efficiency.

Pulverised Coal firing is done by two systems:

- 1) Unit System or Direct System
- 2) Bin or Central System

Figure 2.4 shows the equipments for central and unit system.

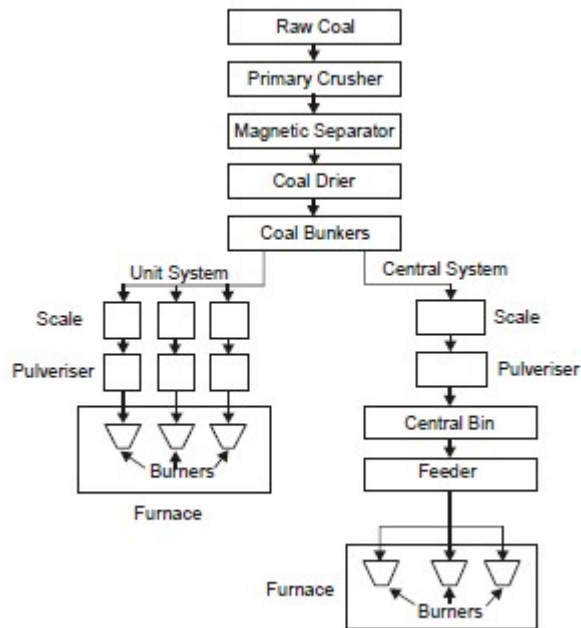


Figure 2.5: Equipments for Central and Unit System[1]

In Unit System, the raw coal from the coal bunker drops on to the feeder. Hot air is passed through coal in the feeder to dry the coal. The coal is then transferred to the pulverising mill where it is pulverised. Primary air supplied to the mill by the fan. The mixture of pulverised coal and primary air then flows to burner where secondary air is added. The system is simple and cheaper than the central system. Also coal transportation system is simple.

In Central System, crushed coal from the raw coal bunker is fed by gravity to a dryer where hot air is passed through the coal to dry it. The dryer may use waste flue gases, preheated air as drying agent. The dry coal is then transferred to the pulverising mill. The pulverised coal obtained is transferred to the pulverised coal bunker. The transporting air is

separated from the coal in the cyclone separator. The primary air is mixed with the coal at the feeder and the mixture is supplied to the burner.

Advantages of pulverized coal firing

1. Low excess air requirement
2. Less fan power
3. Ability to use highly preheated air reducing exhaust losses
4. Higher boiler efficiency
5. Ability to burn a wide variety of coals
6. Fast response to load changes
7. Ability to use fly ash for making bricks etc.
8. Less pressure losses and draught need

Disadvantages

1. Added investment in coal preparation unit
2. Added power needed for pulverizing coal.
3. Investment needed to remove fly ash before ID fan
4. Large volume of furnaces needed to permit desired heat release and to withstand high gas temperature.

2.3 Burner Arrangement

Burners may be arranged in the furnace in different ways that give different flame characteristics. There are three distinct methods:

1. Tangential firing
2. Downshot firing
3. Horizontal firing

2.3.1 Tangential firing

Tangential firing is a method of firing a fuel to heat air in furnace. The flame envelope rotates ensuring thorough mixing within the furnace, providing complete combustion and uniform heat distribution.

The most effective method for producing intense turbulence is by the impingement of one flame on another. This action is secured through the use of burners located in each of the four corners of the furnace. The burner nozzles are so directed that the streams of coal and

air are projected along a line tangent to a small circle, lying in a horizontal plane, at the centre of the furnace. Intensive mixing occurs where these streams meet.

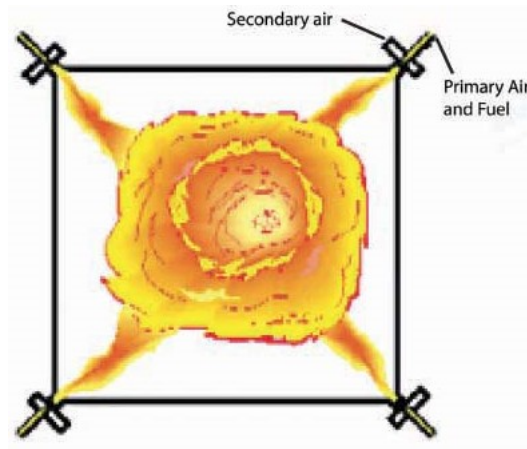


Figure 2.6: Tangential firing[1]

In a tangential firing system the coal is pulverized in coal mills and is carried by primary air to the furnace through coal pipes. The secondary air required for combustion is sent into the furnace through a windbox housing the coal nozzles, oil guns, and the secondary air nozzles. Behind the coal nozzles there are fuel-air dampers which are used for keeping the flame front away from the coal nozzles by at least one meter from the tip. This is required to prevent the coal nozzle tips from getting burnt due to radiation from coal flame. The flame front is predominantly affected by the volatile matter in coal and the fuel air damper is modulated for controlling the flame front. As the fuel air dampers are opened, more secondary air goes through this damper and physically pushes the flame front away. However, when the flame front is already away from the nozzle tip, the fuel air damper needs to be closed fully.

2.4 Secondary Air Damper Control (SADC)

SADC stands for secondary air damper control. The secondary air which is handled by the FD fan passes through the airheater and to the windbox connecting duct which supplies the secondary air to a pair of windboxes. The secondary air is divided into two parts, namely, fuel air and auxiliary air. Fuel air is that air which immediately surrounds the fuel nozzles. Since this air provides a covering for the fuel nozzles it is also called mantle air. Auxiliary air is admitted through compartments above and below the fuel nozzles. Dampers are provided in the windbox compartments so that the correct quantities of air to the individual compartments can be modulated to achieve the better combustion in the

furnace. SADC is an important and salient feature in which few number of windbox dampers are used to distribute air in the furnace for better combustion.

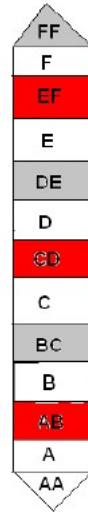


Figure 2.7: Damper Arrangement[1]

There are six fuel (coal) elevation dampers (A,B,C,D,E,F) ; three fuel oil cum auxiliary air dampers (AB,CD,EF) ; and three Auxiliary air dampers (BC,DE,FF). Another damper situated at the bottom most position, namely AA damper is not connected to SADC circuit and operated manually.

2.5 Terminology involved in combustion

Ignition: Ignition is the term used to establish flame in the main fuel employed in the burner. The energy released by the source of ignition excites the fuel molecules and help to release vapour from fuels. Ignition always takes place in the vapour state. A flame is spark-ignited in a flammable mixture only if the spark energy is larger than some critical value known as the minimum ignition energy.

Flame speed is the rate of motion of flame relative to the reactant (fuel +air).

Flame flash back will occur when the reactant's velocity is less than that of flame speed, i.e flame goes back to the source.

Flame blow off will occur when the reactant's velocity is more than that of flame speed (flame is lifted off).

Flame holding - Ensuring the ignited flame is maintained after the removal of the source of ignition, is called as “ flame holding”.

Flame Propagation is the burning velocity of flame front with reference to unburnt gases

Flame stability is the steadiness of the stationary flame (the tendency for the flame to retain given flame envelope even with disturbances in the furnace.)

Volatile Matter is the substance, which distills at low temperature and is released when the coal is heated.

Ashes are nothing but mineral matter left after the complete combustion of fuel. The product of ashes is Silica, Alumina, lime, oxide and bi-sulphide of iron.

Slagging & fouling: If the ash fusion temperature is very low, the ashes will be in molten stage above the ash fusion temperature, which is called as slagging. If the ash fusion temperature is between 850 to 950°C, slagging is expected. If the molten stage ashes along with impurities contact any cooling medium, these impurities will deposit over the cooling medium and affect the passages of flue gas, which is called as fouling. Normally, fouling will be formed at horizontal pass where the SH and RH are located.

Clinker is the product formed in the furnace by ash fusing together with impurities in the coal such as oxide of iron, silica, lime etc.

2.6 Factors affecting the combustion

In order to optimize the combustion in pulverised coal fired boiler, first of all we need to know the influencing factors in combustion. Some of the factors affecting furnace stability or combustion are as follows:

1. Quality of Coal
2. Pulverised Coal fineness
3. Secondary Air Damper Control
4. Burner tilting angle
5. Air fuel ratio
6. Slagging
7. NO_x formation

2.7 Combustion Behaviour

The volatiles mix with air during their release from the particle. If the temperature is sufficiently high, ignition will be spontaneous; however, if the temperature is not high enough, the mixture of air and volatiles can burn as a premixed gaseous flame, even at a long distance from the particle.

If the total air is high, (high excess air) with high turbulence, the temperature liberated by the combustion is also very high, during that time glassy white colour flame is visible.

If the total air is low (low excess air), the flame will be dark yellow and dull. Smoke may be visible, indicating that the combustion is not proper.

If the air is not thoroughly mixed with the vapour of the coal, it will result in longer flame and the heat liberation during combustion is reduced.

Table 2.2: Colour of the flame versus temperature[1]

Colour of the flame	Temperature in ° C
Incipient red flame	525
Dull red heat	700
Dull cherry red heat	800-900
Clear cherry red heat	1000
Deep Orange	1100
Clear Orange	1200
White heat	1300
Bright white heat	1400
Dazzling white heat	1500-1600

2.8 Boiler Performance Monitoring Techniques

In Boiler, there are two monitoring techniques used for continuous monitoring of the boiler.

1. On-Line Monitoring Techniques.
2. Off-Line Monitoring Techniques.

2.8.1 On-Line Monitoring Technique

On-Line Monitoring techniques are monitored by control room operators, in which real time data's are available on their panels. Readings are of Unit-4, Stage- II, WTPS. Boiler data and coal mill data sheet have been given in Table 2.3 and Table 2.4 respectively.

Table 2.3: Boiler data sheet

Parameters	160 MW		210 MW	
Load MW /Coal flow (T/Hr)	160	105	210	140
Total steam flow (T/HR) /Drum pressure (Kg/cm ²)	454	155	657.01	165.41
MS press (L/R) (kg/cm ²)	150	-	150.85	-
PA HDR press (mmwc)	720	-	730	-
FG press at final SH /RH O/L (kg/cm ²)	-12	-5	-16.86	-4
FG press at hori SH /ECO O/L (kg/cm ²)	-6	-32	-11.5	-45.01
FG DP across APH A/B (kg/cm ²)	97	85	140	125.1
FG press at APH A/B O/L (kg/cm ²)	-154	-143	-209.58	-202
SA press across APH A/B (kg/cm ²)	128	104	161.8	158.45
SA DP across APH A/B (kg/cm ²)	80	30	121.49	58.53
SA at windbox L/R (kg/cm ²)	72	69	91.04	89.4
SA flow at APH A/B (T/Hr)	122	133	167.6	180.2
Windbox to furnace DP (mmwc)	79	73	91.62	-
Scan fan disch Pr (mmwc) /HDR press (mmwc)	200	180	207.2	181.36
Furnace press (mmwc)	-2	-	-2	-
SA flow at redund transm L (T/Hr)	131	124	125.7	128
SA flow at redund transm R (T/Hr)	130	142	181.2	184.6
O ₂ in FG %	3.4	3.1	2.35	2.46
Scanner air fan filter DP (mmwc)	15	-	19	-
Total Air/steam flow (T/Hr)	-	-	609.8	551.78
FG temp at PSH /RH O/L	815	650	813.03	731.01
FG temp at FSH /Hori SH O/L	544	425	525	450.8
FW temp at Eco Inlet/Outlet	230	285	245	296
FG temp at APH A/B Inlet/Outlet	322/307	128/142	350/140	336/157
SA temp at windbox L/R	282	290	299	310
PA temp at APH A/B O/L	280	282	286	303
SA temp APH A/B O/L	280	291	301	315
HO/Atomising steam pressure (kg/cm ²)	2.5	6.8	1.03	4.3
Atomising Air press/LDO Burn Press	1.55	-	1.3	-
Instrument Air press (kg/cm ²) / HO temp	6.6	10.5	6.6	117.27

Table 2.4: Coal mill data sheet

Parameters	160 MW		210MW	
LOAD MW /Coal flow (T/Hr)	160	110	210	140
MS (SH) pres (L/R) (kg/cm ²)	150	150	150	150
MS (SH) temp (L/R)	535	535	535	535
SH Attemp (L) temp (I/O)	392	-	-	388
SH Attemp () temp (I/O)	380	-	-	389
SH Spray Control L/R %	62	58	63	60
SH spray ISO Valve I/O (L) T	Open	-	Open	-
SH spray ISO Valve I/O (R) T	Open	-	Open	-
HRH Press (L/R) (kg/cm ²)	25	25	34.5	34.5
HRH Temp (L/R)	515	535	535	-
RH Attemp (L) temp (I/O)	330	-	-	336
RH Attemp (R) temp (I/O)	269	-	-	300
RH spray contol L/R %	0	27	0	38
RH spray ISO valve I/O (L) T	Open	-	Open	-
RH spray ISO valve I/O (R) T	Open	-	Open	-
O ₂ in FG (L/R) %	3.9	-	2.39	2.3
Total Air flow (T/Hr)	530	-	612	-
Total Steam flow (T/Hr)	509	-	650	-
PA HDR Press (mmwc)	720	-	720	-
PA flow -Mills A/B (T/Hr)	R	55	50	54
PA flow -Mills C/D (T/Hr)	54	64	52	51
PA flow -Mills E/F (T/Hr)	62	R	51	R
Air temp Mill Inlet A/B	R	262	275	275
Air temp Mill Inlet C/D	268	260	275	275
Air temp Mill Inlet E/F	265	R	278	R
Coal Air temp Mill O/L A/B	R	94	90	95
Coal Air temp Mill O/L C/D	85	91	97	98
Coal Air temp Mill O/L E/F	100	R	96	R
Coal Mill DP A/B (mmwc)	R	162	215	Def
Coal Mill DP C/D (mmwc)	127	Def	232	162
Coal Mill DP E/F (mmwc)	Def	R	342	R
Current- Mill A/B (AMP)	R	31	30	25
Current- Mill C/D (AMP)	28	37	28	26
Current- Mill E/F (AMP)	28	R	26	R
Coal flow feeders A/B (T/Hr)	R	27	27	27
Coal flow feeders C/D (T/Hr)	29	28	29	30
Coal flow feeders E/F (T/Hr)	28	R	23	R

2.8.2 Off-Line Monitoring Technique

Off-Line Monitoring techniques are monitored at physical locations by specific operators. They have to regular monitor the locations. Readings are of Unit-4, Stage-II, WTPS. Boiler feed pump data and coal mill data have been given in Table 2.5 and Table 2.6 respectively.

Table 2.5: Boiler feed pump data

Parameters	160 MW	210 MW
BFP in service (A/B/C)	4A	-
Disch press of booster pump	18.2	18.5
Bearing 1 Temp	51	53
Bearing 2 Temp	52	49
Bearing 3,4 Temp	54	54
Bearing 5 Temp	54	59
Bearing 6 Temp	69	68
Pressure Regulating valve press	1.5	15
Lub Oil press	3	3
Bearing 7 & 10 Temp	64	65
Working Oil Outlet Temp	65	62
Diff press pump(Booster pump suction pres)	0.05	0.07
Suction Press of booster pump	8.3	10.2
Oil Level	Normal	Normal
Suction Press of BFP pump	8.3	19
Discharge Press of BFP pump	171	186
Balancing leak of press	17.4	18.8

Table 2.6: Coal mill data sheet

Parameters	160 MW	210 MW
Oil Bath Temp 6A	60	46
DE Motor Temp 6A	45	39
NDE Motor Temp 6A	38	60
Oil Bath Temp 6B	57	49
DE Motor Temp 6B	49	41
NDE Motor Temp 6B	39	56
Oil Bath Temp 6C	62	43
DE Motor Temp 6C	45	29
NDE Motor Temp 6C	28	62
Oil Bath Temp 6D	70	49
DE Motor Temp 6D	48	43
NDE Motor Temp 6D	42	70
Oil Bath Temp 6E	57	40
DE Motor Temp 6E	37	36
NDE Motor Temp 6E	33	60

2.9 Coal Analysis

In India, coal is the primary energy source because of its large deposits and availability. Coal originates from vegetable matter which grew years ago. According to geological order of formation, coal may be of different types: 1) Peat, 2) Lignite, 3) Bituminous, 4) Subbituminous, 5) Anthracite.

Anthracite contains more than 86% fixed carbon and less volatile matter. Bituminous coal is the largest group containing 46-86% of fixed carbon and 20-40% of volatile matter. The lower the volatility, the higher the heating value. Lignite is the lowest grade of coal containing moisture as high as 30% and high volatile matter. Peat contains up to 90% moisture and is not attractive as a utility fuel. Peat is not regarded as a rank of coal. Rank carries the meaning of degree of maturation or carbonisation and is a measure of carbon content in coal. Coal is further classified in various categories as shown in Table 3.1

Table 2.7: Different Grades of Coal[3]

Grade	Calorific Value (Kcal/Kg)
A	6200 & above
B	5601 to 6200
C	4941 to 5600
D	4201 to 4940
E	3361 to 4200
F	2401 to 3360
G	1300 to 2400

2.9.1 Proximate & Ultimate Analysis

Proximate Analysis:

This is the easier of two types of coal analysis and the one which supplies readily meaningful information for coal's use in steam generators. The proximate analysis of the coal gives composition of coal in respect of fixed carbon, volatile matter, moisture, and ash.

Fixed carbon is the elemental carbon that exists in coal. In proximate analysis, its determination is approximated by assuming it to be the difference between the 100% and the sum of the percentages of volatile matter, moisture, and ash.

Moisture in the coal exists in two forms as inherent and free moisture. Inherent moisture is the combined moisture and is held in the pores of coal. The inherent moisture is never removed from the coal used for power plants as it is costly procedure. The free moisture is defined as moisture present in the coal which can be removed just by exposing the coal to the natural air flow or by drying with the help of air. When 1 gram sample of coal is subjected to a temperature of about 105^o C for a period of 1 hour, the loss in weight of the sample gives the moisture content of the coal.

When 1 gram sample of coal is placed in a covered platinum crucible and heated to 950^o C and maintained at that temperature for about 7 minute there is a loss in weight due to elimination of moisture and volatile matter. The latter may be determined since moisture has been calculated from the previous test. Volatile matter consists of hydrogen and certain hydrocarbon compounds which can be removed from the coal by simply heating it.

Ash is another most undesirable constituent of coal. The ash present in the coal is of two forms as fixed ash and free ash. The fixed ash present in the coal comes from the original vegetable matter and it cannot be removed from coal before burning the coal. The free ash comes with the coal in the form of clay, shale and pyrites. The free ash can be reduced or removed by mechanical processing of coal such as washing and screening. By subjecting 1 gram of sample in an uncovered crucible to a temperature of about 720^o C until the coal is

completely burned, a constant weight is reached, which indicates there is only ash remaining in the crucible.[2]

Ultimate Analysis:

The proximate analysis of coal does not give any idea about the suitability of coal for the purpose of heating. It is not possible to find out the calorific value of coal with the help of proximate analysis. To find out the chemical analysis of coal, like carbon, hydrogen, oxygen, nitrogen, sulphur and ash, ultimate analysis of coal is generally used.

2.10 Bomb Calorimeter

Calorific value of coal may be considered as a single really significant parameter for characterizing the coal. The design of boiler is based on gross calorific value of coal. It is used to calculate boiler efficiency and heat rate. On complete combustion of 1 gm of coal, the heat generated in calories is called calorific value of coal. It can be measured by bomb calorimeter accurately. The unit of calorific value is kcal/Kg. It is used for determination of heat of combustion, calorific value and sulphur contents of solid and liquid fuels. The Bomb body and lid are machined from corrosion resisting stainless steel rod.

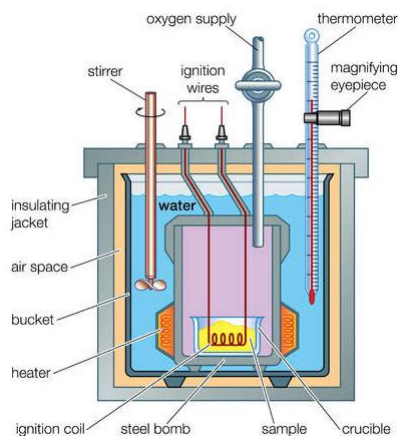


Figure 2.8: Bomb Calorimeter[3]

Basically, as shown in Figure 3.1, bomb calorimeter consists of a small cup to contain the sample, oxygen, a stainless steel bomb, water, a stirrer, a thermometer, the dewar or insulating container and ignition circuit to the bomb.

A bomb calorimeter is a type of constant volume calorimeter used in measuring the heat of combustion of a particular reaction. Electrical energy is used to ignite the fuel; as the fuel is burning, it will heat up the surrounding air, which expands and escapes through a tube

that leads the air out of the calorimeter. When the air is escaping through the copper tube it will also heat up the water outside the tube. The change in temperature of the water allows for calculating calorie content of the fuel.

2.11 Calculation of air required for complete combustion

As per coal analysis by Wanakbori thermal power station, proximate analysis and ultimate analysis are shown in Table 3.2.

Table 2.8: Proximate and Ultimate Analysis

Proximate Analysis%		Ultimate Analysis%	
Moisture	8.86	Moisture	8.86
Ash	37.12	Ash	37.12
Volatile Matter	23.3	Hydrogen	2.92
Fixed Carbon	30.6%	Total Carbon	39.08
		Nitrogen	1.82
		Sulphur	0.56
		Oxygen	9.64

Now, theoretical air required per kg of fuel is given by

$$W_T = 11.5C + 34.5\left(H - \frac{O}{8}\right) + 4.3S$$

$$W_T = (11.5 \times 0.3908) + 34.5\left(0.0292 - \frac{0.0964}{8}\right) + (4.3 \times 0.0056)$$

$$W_T = 4.4942 + 1.0074 - 0.415725 + 0.02408$$

$$W_T = 5.11 \text{ kg of air/kg of fuel.}$$

Actual air required, $W_A = 6.39$ kg of air/kg of fuel.

$$\text{Percentage excess air required} = \frac{W_A - W_T}{W_T} \times 100 = \left(\frac{6.39 - 5.11}{5.11}\right) \times 100 = 25.04\%$$

2.12 Recent Work

2.12.1 Experimental and Theoretical Work

A method is presented by Benyuan Huang et. al. [4] to optimize coal combustion based on flame image processing technique and concept of introducing RES into combustion control circuit of coal fired power plant. It showed that by optimal control strategy, we can ensure stability of load and main steam pressure by adjusting secondary air for optimized A/F flow rate and thereby strengthened and stabilized combustion conditions can be achieved in

furnace. Also boiler efficiency increased and NOx emissions reduced at optimized operating conditions.

Ren Jianxing et.al.[5] studied a 300 MW Coal fired unit using three kinds of mixed coal A, B and C. Under the rated load conditions characteristics of coal and burning characteristics were studied. The objective was to optimize combustion and enhance boiler efficiency by undergoing experimental analysis based on parameters such as burning status, flame transparency, unburned combustible in flue gas and exhaust gas temperature. Based on results of experiments, the results showed that mixed coal A was found better than mixed coal B and C on above mentioned parameter and hence it helps to optimize combustion and boiler efficiency.

Ji Zheng Chu et. al.[6] proposed their study on new constrained procedure using artificial neural network as models for target processes. Information analysis based on random search, fuzzy c-mean clustering and minimization of information energy is performed iteratively in proposed procedure. ANN offer an alternative approach to model process behaviour. It is based on extracting imbedded pattern from data that describes the relationship between input and output in any process phenomena. It is capable of handling complex and non-linear problems processing information rapidly and reduces engineering efforts required in model developments. It has been known that delaying mixing of combustion air with fuel is an effective means to reduce production of NOx in combustion process. Also, we came to know that there exists a best air ratio at which thermal efficiency achieves maximum for given fuel.

Combustion optimization has been proved to be an effective way to reduce NOx emissions and unburned carbon in fly ash by carefully setting operational parameters of boiler. Feng Wu et. al.[7]employed Support Vector Regression (SVR) to build NOx emissions and carbon unburnt models. Thereafter improved Strength Pareto Evolutionary Algorithm (SPEA2) , the new multi objective particle Swarm Optimizer (OMOPSO), the Archive-Based Hybrid Scatter Search method (AbYSS) and cellular genetic algorithm for multi objective optimization (MOCcell) were used for this purpose. Here the authors compared various algorithms in terms of quality, convergence, accuracy and diversity. The results shows that the method combining SVR and multi objective algorithm could effectively reduce NOx emissions and unburned carbon in fly ash. The results also show that OMOPSO algorithm is best in terms of accuracy and convergence rate. AbYSS has better diversity but poor accuracy. SPEA2 is slowest algorithm and its execution time is one order higher than others. Therefore OMOPSO and MOCcell are proposed algorithm for online multi objective optimization of coal fired boiler.

Barry E Pulskamp et.al.[8] studied on 440 MW pulverized coal fueled unit. The steam generator had not been performing to design expectations. So number of modifications was made to the boiler. It was noted that the furnace exit gas temperature was varying from other variables, and those variables were suspected to be combustion air and fuel balance. The identification and quantification of the combustion variables was undertaken by a Comprehensive Test Program followed by an approach entitled in ASME paper. It was found that on this boiler, furnace exit had number of individual points that were in a reducing atmosphere, or zero excess oxygen. Since many of the opportunities for improvement that were experienced by them on this boiler were slagging related, this was a significant problem. The comprehensive testing confirmed that significant improvements could be achieved in boiler and steam cycle performance. Using Secondary air balancing to each corner and removing the lower perforated plate sections from each four corners, slag formation reduced in that areas and confirmed boiler sensitivity to furnace slagging in areas of depleted oxygen.

Li Gang Zheng et.al.[9] studied on optimisation algorithms to achieve low NOx emissions from a coal utility boiler using combustion modifications. Support vector regression was proposed in the first stage to model the relation between NOx emissions and operational parameters of utility boiler. A mass of NOx emissions data from the utility boiler was employed to build the SVR model. The predicted NOx emissions from SVR model was in good agreement with measured. In second stage, the authors used two variants of ant colony optimization as well as genetic algorithm and particle swarm optimization were employed to find the optimum operating parameters to reduce NOx emissions. The results show that ant colony optimization outperforms those of classical genetic algorithm and particle swarm optimization in terms of quality of solution and convergence rate. It is also noted that PSO have the worst quality of solution among all algorithms for all studied cases.

Ilamathi P et.al.[10] proposed predictive modelling method of nitrogen oxides emission from a 210 MW coal fired plant. The combustion parameters were used as inputs and nitrogen oxides as output of the model. Using back propagation feed forward neural network, the predicted values of the model for full load condition were verified with the actual values. The optimum level of input operating conditions for low nitrogen oxides emission was determined by using simulated annealing approach. It was concluded that combined approach of neural network and simulated annealing for predicting and optimizaing nitrogen oxides emission gives accurate prediction and is one of the suitable way to predict emissions under various operating conditions.

2.12.2 CFD Work

Hao Zhou et. al.[11] introduced an approach to predict the nitrogen oxides emission characteristics of large capacity pulverized coal fired boiler with artificial neural networks. The NOx emission and carbon burnout characteristics were investigated through parametric field experiments. The effects of over fire air flow rates, coal properties, boiler load, air distribution scheme and nozzle tilt were studied. On the basis of experimental results, an ANN was used to model the NOx emission characteristics and the carbon burnout characteristics. It is noted that when compared with other modeling techniques, such as CFD approach, the ANN approach is more convenient and direct, and can achieve good prediction effects under various operating conditions. It is concluded that it is convenient to employ the ANN model and optimization method developed in this paper to model the combustion characteristics using large amount of training data downloaded from DCS.

Risto V Filkoski et. al. [12] applied a method for handling two phase reacting flow for prediction of pulverised coal combustion in large scale boiler furnace and to assess ability of model to predict existing power plant data. This paper presents principal steps and results of numerical modeling of furnace. The CFD/CTA approach was utilised for creation of three dimensional model, including platen super heater in upper part of furnace. Standard k epsilon model was employed for description of turbulent flow. Radiation heat transfer is computed by means of simplified P-N model. Simulation results concerning furnace walls, thermal efficiency and combustion efficiency shows good results corresponding with plant data.

2.13 Conclusion of Literature Review

After studying the literatures on optimization of combustion in coal fired boilers, the following conclusions can be drawn.

1. The new concept of combustion control scheme namely Radiant Energy Signal (RES) based on flame image processing is very helpful in improving the performance of installed power plants because it investigates the use of flame images collected in a boiler to provide information on the internal state and it forecast optimal air fuel rate which ensures stability of load and main steam pressure. The boiler unit performances such as operating conditions, nitrogen oxide emissions and thermal efficiency can be analyzed.
2. With diversification of coal, there are big differences between burning coal and design coal, this affect on the safety of running. Under the rated load, characteristics of coal can be studied. In paper[5], three mixed coal were chosen and studied experimentally by

elementary analysis and industrial analysis, and results indicated that under conditions of experiments and slag severity, serial arrangement of three mixed coals were given. Boiler efficiency of mixed coal A was higher than that of mixed coal B and C.

3. Artificial Neural Network (ANN) offer an alternative approach to model process behaviour. It is based on extracting imbedded pattern from data that describes the relationship between input and output in any process phenomena. It is capable of handling complex and non-linear problems processing information rapidly and reduces engineering efforts required in model developments.
4. Comparison in terms of quality, divergence, accuracy can be conducted with the help of various algorithms like Strength pareto evolutionary algorithm, Multi objective particle swarm optimizer, Archive-Based hybrid scatter search and cellular genetic algorithm for multi objective optimization which will also be helpful in knowing the best algorithm to reduce nitrogen oxides emissions and unburnt carbon in fly ash under different opearating conditions.
5. It is noted that when compared with other modeling techniques, such as CFD approach, the ANN approach is more convenient and direct, and can achieve good prediction effects under various operating conditions. But ANN has its limitations too. Construction of network for complex projects is complicated and time consuming due to trial and error approach. Also to develop a clear logical network is troublesome. The planning and implementation of networks require personnel trained in the network methodology.

Chapter 3

Optimization of Combustion

This chapter includes coal flow balancing which includes clean air test and dirty air test (coal+air). Also optimization of combustion using secondary air damper have been carried out from the analysis of optimum value of excess air.

3.1 Pulverised Coal Flow Balancing

The first step in optimizing combustion system performance is to balance the air and fuel flowing through the coal pipes, i.e the pipes that convey the air/fuel mix from the pulveriser to the individual burners in the furnace wall. The system is said to be balanced when the flow of air and fuel flowing through the pipes are within certain specific limits. The measurements related to flow balancing plays a crucial role in adjusting fuel and air flow through pipes.[13]

Balancing air and fuel flow requires carefully collection of a number of measurements, including pipe static pressure, pipe temperature, dirty air velocities, fuel flow and air flow from coal pipe. The following discussion focuses on the importance of clean air test and dirty air test for proper flow balancing.

3.1.1 Clean Air Flow Test

Clean air flow test in milling system is carried out to check whether the airflow variation between the pulverised coal pipes of a mill is within allowable limit and thereby to ensure that correct size orifices are installed in coal pipes for equalizing the air flow.

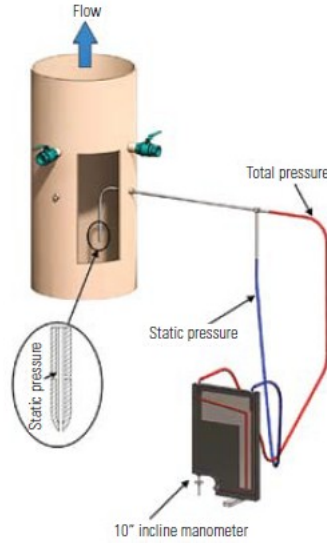


Figure 3.1: Clean Air Test[13]

A clean air test is conducted to balance the system resistance of each burner line leaving each pulveriser. This measurement is made with no coal flowing into the pulverisers. The clean air test conducted on coal pipe is completed by multiple point measurements using a standard pitot tube. The deviation in air flow through each corners are then plotted on a graph for ease of analysis. Clean air tests have been conducted under steady state conditions with completely stable system temperatures.

In clean air test, the measurements of velocity head, static pressure and differential pressure was taken at each corners. Then calculation of air flow and deviations in air flow through each corners have been carried out for analysing whether the air flow is within specific limit or not. In clean air test, $\pm 5\%$ deviations of airflow are satisfactory. Table 3.1 shows clean air test readings at four corners.

Table 3.1: Clean Air Test readings

	CORNER-1		CORNER- 2		CORNER-3		CORNER- 4	
	$V_h(\text{mmwc})$		$V_h(\text{mmwc})$		$V_h(\text{mmwc})$		$V_h(\text{mmwc})$	
POINTS	PORT-1	PORT-2	PORT-1	PORT-2	PORT-1	PORT-2	PORT-1	PORT-2
1	2	2	1.2	2.1	2.3	1.6	2.2	2.4
2	2	2	1.7	2.2	2.5	2	2.6	2.7
3	2	2	1.9	2.3	2.3	2.5	2.8	1.9
4	2	2	2.1	2.7	2.8	2.5	2.9	2.7
5	2	2	2.3	2.6	2.9	2.4	2.8	2.1
6	2	2	2.6	2	2	2.6	2.8	2
7	2	2	2.7	2.1	2.2	2.7	2.1	2.1
8	2	2	2	2	2.1	1.8	2.2	2
9	2	2	1.9	1.7	2.2	2	1.8	2.2
10	0	2	1	1.8	2.3	1.7	2.8	2
11	0	0	2.8	2.1	2.2	2.1	2.2	2.5
12	0	0	2.7	2.3	2.6	1.2	2.7	2.5
Sampler DP (mmwc)	1.55		2.59		2.74		2.93	
Temp ($^{\circ}\text{C}$)	38.76		39.96		38.96		39.76	
Static Pressure (mmwc)	1.3		1.8		2.3		2	
Density (kg/m^3)	1.107		1.104		1.1086		1.1051	
Velocity (m/s)	21.12		27.31		28.02		29.02	
Air Flow (T/hr)	12.05		15.54		16.01		16.53	

In the above table, other parameters except airflow was given. So we calculated airflow as follows[14]:

$$\text{Airflow} = \text{Velocity} \times \text{Area} \times \text{Density}$$

$$\text{Area} = 0.14318 \text{ m}^2(\text{given})$$

$$\text{For Corner 1, Airflow} = 21.12 \times 0.14318 \times 1.107 \times 3.6 = 12.05 \text{ T/hr}$$

$$\text{For Corner 2, Airflow} = 27.31 \times 0.14318 \times 1.104 \times 3.6 = 15.54 \text{ T/hr}$$

$$\text{For Corner 3, Airflow} = 28.02 \times 0.14318 \times 1.1086 \times 3.6 = 16.01 \text{ T/hr}$$

$$\text{For Corner 4, Airflow} = 29.02 \times 0.14318 \times 1.1051 \times 3.6 = 16.53 \text{ T/hr}$$

3.1.2 Dirty Air Flow Test

In dirty air test, dirty air velocities are measured to determine airflow and coal flow through coal pipe. It is carried out to check whether the air flow and fuel flow deviations are within the allowable limit and thereby to ensure that correct size orifices are installed in coal pipe for equalizing the air and fuel flow.

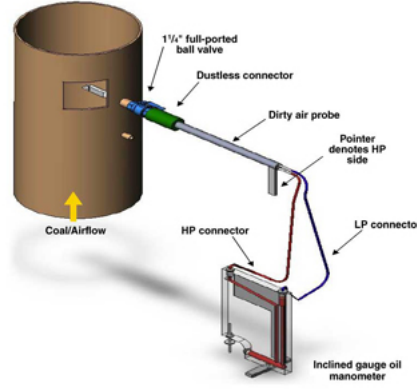


Figure 3.2: Dirty Air Test[13]

In dirty air test, measurements are made with coal flowing into the pulverisers. Here, dustless connector is installed at ball valve to ensure coal containment in coal transport pipe during traverse. In dirty air test, readings of velocity head, static pressure, temperature were taken at four corners. Then, calculation of velocity, air flow and fuel flow have been carried out at four corners. Also calculations for deviations in air flow and fuel flow have been carried out to analyse whether the deviations in air and fuel flow are within allowable limits.

The formulas used in dirty air test are as follows[15]:

$$(V_h)^{\frac{1}{2}} = \frac{(V_{h1})^{\frac{1}{2}} + (V_{h2})^{\frac{1}{2}} + \dots + (V_{h24})^{\frac{1}{2}}}{\text{No of traverse points}}$$

$$\text{Velocity} = 1095 \times (V_h)^{\frac{1}{2}} \times (\text{probe factor}) \times 0.00508 / (\text{Density})^{\frac{1}{2}}$$

$$\text{Airflow} = \text{Velocity} \times \text{Area} \times \text{Density}$$

$$\text{Fuel flow} = (\text{Sample Weight} \times 60 \times \text{Pipe area} \times 0.000453592) / (453.6 \times 4 \times \text{Sample tip area})$$

$$\% \text{ deviation in velocity} = \left(\frac{\text{Actual Velocity} - \text{Average Velocity}}{\text{Average Velocity}} \right) \times 100$$

$$\% \text{ deviation in air flow} = \left(\frac{\text{Actual Airflow} - \text{Average Airflow}}{\text{Average Airflow}} \right) \times 100$$

$$\% \text{ deviation in fuel flow} = \left(\frac{\text{Actual Fuel flow} - \text{Average Fuel flow}}{\text{Average Fuel flow}} \right) \times 100$$

Following Table 3.2 shows readings of dirty air tests.

Table 3.2: Dirty Air Test readings

	CORNER-1		CORNER- 2		CORNER-3		CORNER- 4	
	$V_h(\text{mmwc})$		$V_h(\text{mmwc})$		$V_h(\text{mmwc})$		$V_h(\text{mmwc})$	
POINTS	PORT-1	PORT-2	PORT-1	PORT-2	PORT-1	PORT-2	PORT-1	PORT-2
1	1.5	1.9	1.9	1.7	1.8	1.5	1.2	1.4
2	2.3	1.2	2	1.8	1.9	2.5	2.4	2.6
3	1.6	2.3	2.1	1	2.1	2.4	2.3	2.4
4	2	2.4	2.1	1.3	2.3	3	2.5	2.8
5	1.6	1.5	2.1	2.2	2.4	3.1	2.7	2.5
6	2.7	2.7	1.4	1.3	2.7	2.8	2.8	2.1
7	2.8	2.9	1.3	1.5	2.8	2.4	2.4	2
8	2.4	2.7	1.3	1.4	2.7	2.8	2.2	2.2
9	1.5	2.8	2.2	1.5	2.6	2.8	2.3	2.3
10	1.3	2.7	2.2	1.2	2.6	2.5	2.4	2
11	2.3	2.7	1.9	1.3	2.5	2.6	2.3	2.2
12	1.6	2.6	1.6	1.9	2.5	2.8	2	2.3
Sampler DP (mmwc)	2.66		2.07		3.09		2.78	
Temp ($^{\circ}\text{C}$)	74.93		78.42		73.33		76.92	
Static pressure (mmwc)	0.3		0.6		1		1.2	
Sampling weight (grams)	486.91		381.53		577.75		505.07	
Sqrt.vh (mmwc)	1.46		1.29		1.98		1.5	
Density (kg/m^3)	0.988		0.98		0.994		0.998	
Velocity (m/s)	29.12		25.88		31.38		29.95	
Air Flow (T/hr)	14.36		13.08		16.08		15.42	
Fuel Flow (T/hr)	5.36		4.2		6.36		5.56	
A/F Ratio	2.77		3.12		2.53		2.77	

The calculations for dirty air test are as follows [14]:

1) Here probe factor, $k = 0.98$

$$2) (V_h)^{\frac{1}{2}} = \frac{(V_{h1})^{\frac{1}{2}} + (V_{h2})^{\frac{1}{2}} + \dots + (V_{h24})^{\frac{1}{2}}}{\text{No of traverse points}}$$

$$\text{For Corner 1, } (V_h)^{\frac{1}{2}} = \frac{(1.5)^{\frac{1}{2}} + (2.3)^{\frac{1}{2}} + \dots + (2.6)^{\frac{1}{2}}}{24} = 1.46$$

$$\text{For Corner 2, } (V_h)^{\frac{1}{2}} = \frac{(1.9)^{\frac{1}{2}} + (2)^{\frac{1}{2}} + \dots + (1.9)^{\frac{1}{2}}}{24} = 1.29$$

$$\text{For Corner 3, } (V_h)^{\frac{1}{2}} = \frac{(1.8)^{\frac{1}{2}} + (1.9)^{\frac{1}{2}} + \dots + (2.8)^{\frac{1}{2}}}{24} = 1.58$$

$$\text{For Corner 4, } (V_h)^{\frac{1}{2}} = \frac{(1.2)^{\frac{1}{2}} + (2.4)^{\frac{1}{2}} + \dots + (2.3)^{\frac{1}{2}}}{24} = 1.50$$

$$3) \text{ Velocity} = 1095 \times (V_h)^{\frac{1}{2}} \times (\text{probe factor}) \times 0.00508 / (\text{Density})^{\frac{1}{2}}$$

$$\text{For corner 1, Velocity} = (1095 \times 1.46 \times 0.98 \times 0.00508) / (0.24837) = 32.04 \text{ m/s}$$

$$\text{For corner 2, Velocity} = (1095 \times 1.29 \times 0.98 \times 0.00508) / (0.2568) = 27.38 \text{ m/s}$$

$$\text{For corner 3, Velocity} = (1095 \times 1.98 \times 0.98 \times 0.00508) / (0.3250) = 33.21 \text{ m/s}$$

$$\text{For corner 4, Velocity} = (1095 \times 1.5 \times 0.98 \times 0.00508) / (0.2580) = 31.69 \text{ m/s}$$

4) Airflow = Velocity x Area x Density

$$\text{For Corner 1, Airflow} = 32.04 \times 0.14318 \times 0.988 \times 3.6 = 16.31 \text{ T/hr}$$

$$\text{For Corner 2, Airflow} = 27.38 \times 0.14318 \times 0.980 \times 3.6 = 13.83 \text{ T/hr}$$

$$\text{For Corner 3, Airflow} = 33.21 \times 0.14318 \times 0.994 \times 3.6 = 17.01 \text{ T/hr}$$

$$\text{For Corner 4, Airflow} = 31.69 \times 0.14318 \times 0.998 \times 3.6 = 16.30 \text{ T/hr}$$

5) Fuel flow = (Sample Weight x 60 x Pipe area x 0.000453592) / (453.6 x 4 x Sample tip area)

$$\text{Here, Sample tip area} = 0.0021 \text{ ft}^2 (\text{given})$$

$$\text{Pipe area} = 0.14318 \text{ m}^2 = 1.54117 \text{ ft}^2$$

$$\begin{aligned} \text{For Corner 1, Fuel flow} &= (486.91 \times 60 \times 1.54117 \times 0.000453592) / (453.6 \times 4 \times 0.0021) \\ &= 5.36 \text{ T/hr} \end{aligned}$$

$$\begin{aligned} \text{For Corner 2, Fuel flow} &= (381.53 \times 60 \times 1.54117 \times 0.000453592) / (453.6 \times 4 \times 0.0021) \\ &= 4.20 \text{ T/hr} \end{aligned}$$

$$\begin{aligned} \text{For Corner 3, Fuel flow} &= (577.75 \times 60 \times 1.54117 \times 0.000453592) / (453.6 \times 4 \times 0.0021) \\ &= 6.36 \text{ T/hr} \end{aligned}$$

$$\begin{aligned} \text{For Corner 4, Fuel flow} &= (505.07 \times 60 \times 1.54117 \times 0.000453592) / (453.6 \times 4 \times 0.0021) \\ &= 5.56 \text{ T/hr} \end{aligned}$$

6) Deviations in Clean air test

Deviation in Velocity are calculated as follows:

$$\% \text{ deviation in velocity} = \left(\frac{\text{Actual Velocity} - \text{Average Velocity}}{\text{Average Velocity}} \right) \times 100$$

$$\text{For Corner 1, } \% \text{ deviation in velocity} = \left(\frac{21.12 - 26.37}{26.37} \right) \times 100 = -19.9$$

$$\text{For Corner 2, } \% \text{ deviation in velocity} = \left(\frac{27.31 - 26.37}{26.37} \right) \times 100 = 3.56$$

$$\text{For Corner 3, } \% \text{ deviation in velocity} = \left(\frac{28.02 - 26.37}{26.37} \right) \times 100 = 6.26$$

$$\text{For Corner 4, } \% \text{ deviation in velocity} = \left(\frac{29.02 - 26.37}{26.37} \right) \times 100 = 10.05$$

Deviations in Airflow are calculated as follows:

$$\% \text{ deviation in air flow} = \left(\frac{\text{Actual Airflow} - \text{Average Airflow}}{\text{Average Airflow}} \right) \times 100$$

$$\text{For Corner 1, } \% \text{ deviation in air flow} = \left(\frac{12.05 - 15.03}{15.03} \right) \times 100 = -19.83$$

$$\text{For Corner 2, } \% \text{ deviation in air flow} = \left(\frac{15.54 - 15.03}{15.03} \right) \times 100 = 3.39$$

$$\text{For Corner 3, } \% \text{ deviation in air flow} = \left(\frac{16.01 - 15.03}{15.03} \right) \times 100 = 6.52$$

$$\text{For Corner 4, } \% \text{ deviation in air flow} = \left(\frac{16.53 - 15.03}{15.03} \right) \times 100 = 9.98$$

7) Deviations in Dirty air test

Deviation in Velocity are calculated as follows:

$$\% \text{ deviation in velocity} = \left(\frac{\text{Actual Velocity} - \text{Average Velocity}}{\text{Average Velocity}} \right) \times 100$$

$$\text{For Corner 1, } \% \text{ deviation in velocity} = \left(\frac{32.04 - 31.08}{31.08} \right) \times 100 = 3.08$$

$$\text{For Corner 2, } \% \text{ deviation in velocity} = \left(\frac{27.38 - 31.08}{31.08} \right) \times 100 = -11.9$$

$$\text{For Corner 3, } \% \text{ deviation in velocity} = \left(\frac{33.21 - 31.08}{31.08} \right) \times 100 = 6.85$$

$$\text{For Corner 4, } \% \text{ deviation in velocity} = \left(\frac{31.69 - 31.08}{31.08} \right) \times 100 = 1.96$$

Deviations in Airflow are calculated as follows:

$$\% \text{ deviation in air flow} = \left(\frac{\text{Actual Airflow} - \text{Average Airflow}}{\text{Average Airflow}} \right) \times 100$$

$$\text{For Corner 1, } \% \text{ deviation in air flow} = \left(\frac{16.31 - 15.8}{15.8} \right) \times 100 = 3.22$$

$$\text{For Corner 2, } \% \text{ deviation in air flow} = \left(\frac{13.83 - 15.8}{15.8} \right) \times 100 = -12.46$$

$$\text{For Corner 3, } \% \text{ deviation in air flow} = \left(\frac{17.01 - 15.8}{15.8} \right) \times 100 = 7.65$$

$$\text{For Corner 4, } \% \text{ deviation in air flow} = \left(\frac{16.30 - 15.8}{15.8} \right) \times 100 = 3.16$$

Deviations in Fuel flow are calculated as follows:

$$\% \text{ deviation in fuel flow} = \left(\frac{\text{Actual Fuel flow} - \text{Average Fuel flow}}{\text{Average Fuel flow}} \right) \times 100$$

$$\text{For Corner 1, } \% \text{ deviation in fuel flow} = \left(\frac{5.36 - 5.37}{5.37} \right) \times 100 = -0.19$$

$$\text{For Corner 2, } \% \text{ deviation in fuel flow} = \left(\frac{4.20 - 5.37}{5.37} \right) \times 100 = -21.78$$

$$\text{For Corner 3, } \% \text{ deviation in fuel flow} = \left(\frac{6.36 - 5.37}{5.37} \right) \times 100 = 18.4$$

$$\text{For Corner 4, } \% \text{ deviation in fuel flow} = \left(\frac{5.56 - 5.37}{5.37} \right) \times 100 = 3.53$$

3.2 Secondary Air Damper Control

The secondary air which is handled by the FD fan passes through the airheater and to the windbox connecting duct which supplies the secondary air to a pair of windboxes. The secondary air is divided into two parts, namely, fuel air and auxiliary air. Fuel air is that air which immediately surrounds the fuel nozzles. Since this air provides a covering for the fuel nozzles it is also called mantle air. Auxiliary air is admitted through compartments above and below the fuel nozzles. Dampers are provided in the windbox compartments so that the correct quantities of air to the individual compartments can be modulated to achieve the better combustion in the furnace. SADC is an important and salient feature in which few number of windbox dampers are used to distribute air in the furnace for better combustion[16].

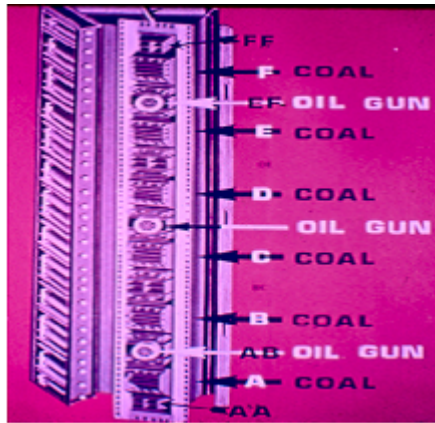


Figure 3.3: Damper arrangement[16]

The secondary air dampers are named after the elevation on the boiler as follows:

Dampers A, B, C, D, E and F are provided at four corner of the furnace. These are also called fuel air dampers. These dampers supply the secondary air for combustion of coal and hence remain open for those elevations, which are in service.

Dampers AB, CD and EF are placed between A and B elevation, C and D elevation, E and F elevation respectively. For the elevation where oil guns are not in service, these dampers modulate to supply the required quantity of air.

Dampers AA, BC, DE, FF are auxiliary air dampers and placed between B and C elevation, C and D elevation and at bottom and top of furnace which provide the additional air required for combustion.

3.3 Different losses associated with excess air

In practice, if a fuel is burned with only the theoretical amount of excess air present, then the combustion will be very poor due to incomplete mixing of the air with the fuel. Hence it is necessary to supply more air than theoretical air required and this is known as excess air. If the amount of air supplied is higher than required, it will result into increase in dry flue gas loss, boiler efficiency reduction, erosion of heat transfer surface due to high gas velocity etc. If the amount of air supplied is lower than required, it will result into incomplete combustion, increase in unburnt carbon losses and soot formation[17].

The different losses mainly influenced by excess air are as follows:

1. Dry flue gas loss.
2. Incomplete combustion loss.

1) Dry flue gas loss

This loss is due to residual thermal energy contained in dry flue gas when its temperature is low for further useful work. At this point it is exhausted to atmosphere. This loss is known as stack loss. It constitutes the largest portion of boiler losses.

2) Incomplete combustion loss

This loss is a result of burning carbon to carbon monoxide instead of carbon dioxide due to insufficient oxygen required. This loss is also known as incomplete combustion loss. This loss is high when excess air is very less or zero, but rapidly falls to zero as more excess air is admitted.

Combined heat loss

If above mentioned losses are added, then it results into combined heat loss. This loss decreases as excess increases, reaches minimum and then increases as still more excess air is added. Thus there is only one quantity of excess air which will give the lowest loss for the combustion of a particular fuel. In other words, there is only one value of excess air which will give minimum heat losses and maximum efficiency.

3.4 Analysis of Optimum excess air

The analysis for finding an optimum air supply is found out at full load. By determining the percentage change in heat loss with percentage change in excess air, optimum quality of excess air supply is to be found. When heat losses is minimum, at that point excess air is minimum and efficiency is maximum. To find out the air supplied at which heat losses

are minimum, design parameters of boiler were considered. The analysis for heat losses at different amount of air supplied are shown in Appendix A.

3.4.1 Dry flue gas loss

This loss basically depends upon the mass supplied and the flue gas temperature. Figure 3.4 shows that as the amount of air supplied increases, the amount of mass supplied and the outlet flue gas temperature increases in other words dry flue gas loss increases.

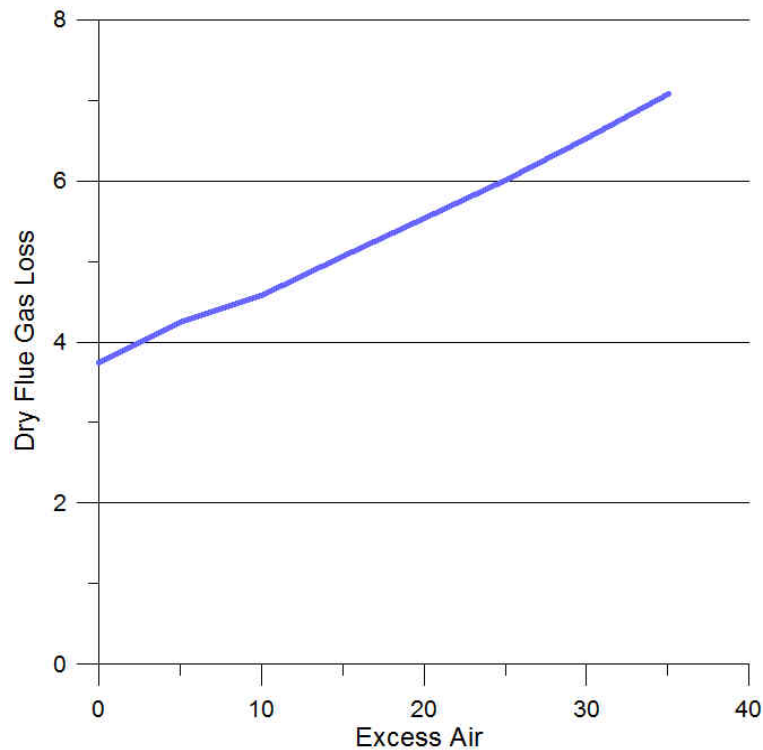


Figure 3.4: Dry flue gas loss vs Excess air

3.4.2 Incomplete combustion loss

Incomplete combustion loss is formation of carbon monoxide instead of carbon dioxide during combustion. As shown in Figure 3.5, when the amount of air supplied is higher than the optimal value of excess air, the incomplete combustion loss is very less and reduces at constant rate but when the amount of air supplied is lower than the optimal value of excess air than incomplete combustion loss increases very sharply.

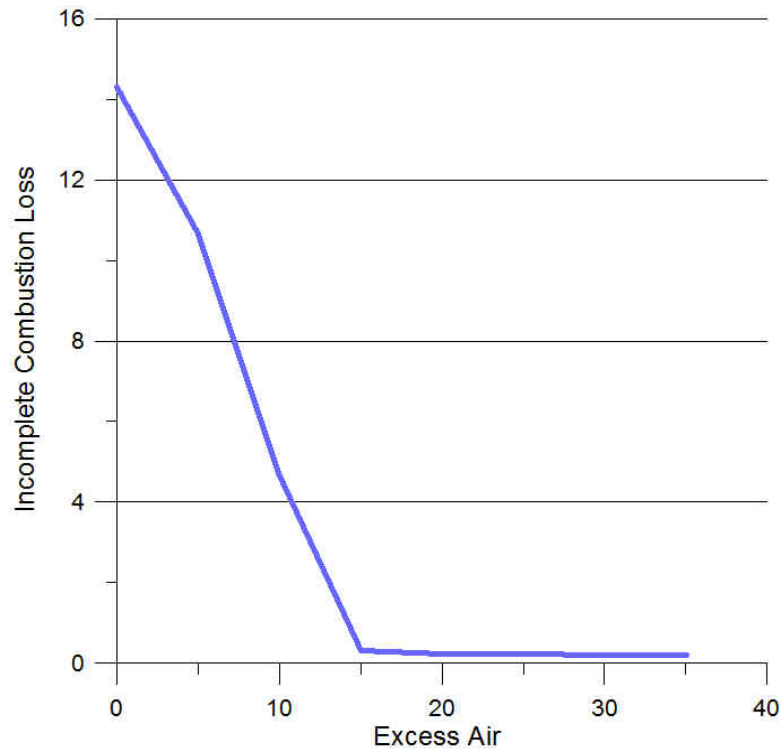


Figure 3.5: Incomplete combustion loss vs Excess air

3.4.3 Combined heat loss

Figure 3.6 shows result of combined heat losses. This loss is minimum when the amount of excess air supplied is 15% as shown in figure. With increase or decrease of the optimum value of excess air, heat losses increases. Thus after analysis, it has been found that at 15% optimum value of excess air, heat losses are minimum and efficiency is maximum.

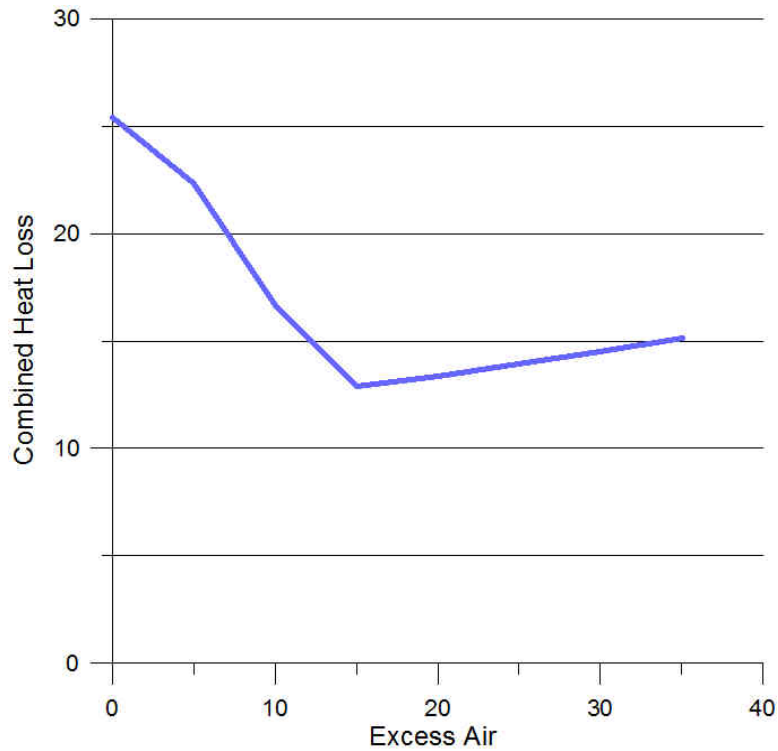


Figure 3.6: Combined heat loss vs Excess air

3.5 Boiler efficiency before correcting damper position

3.5.1 Coal analysis and other operating parameters

The proximate analysis and ultimate analysis of coal carried out in chemical laboratory is shown in Table 3.3. The operating parameters are taken during full load condition. The parameters are shown in Table 3.4.

Table 3.3: Proximate and Ultimate analysis

Proximate Analysis		Ultimate Analysis	
Moisture	12 %	Carbon	43.15 %
Ash	33.76 %	Hydrogen	2.99 %
Volatile Matter	23.07 %	Oxygen	5.78 %
Fixed Carbon	31.17 %	Sulphur	0.5 %
GCV	3850 kcal/kg	Nitrogen	1.82 %
		Moisture	12 %
		Ash	33.76 %

Table 3.4: Operating Parameters

Parameters	Values
Flue gas temperature	180 °C
% O ₂ in F.G	3.9
% CO ₂ in F.G	12.85
% CO in F.G	0.005
Dry bulb temperature	29 °C
% Combustible in fly ash	0.81
% Combustible in botom ash	2.8
Humidity factor	0.015
CV of carbon	8084 kcal/kg

3.5.2 Heat losses and Boiler Efficiency

Table 3.5 shows heat losses in boiler and boiler efficiency calculated according to “Heat Loss Method” [17].

Table 3.5: Heat losses and Boiler efficiency before correcting damper position

Calculated Parameters	Values
Theoretical air required (kg/kg of fuel)	5.82
Actual air supplied (kg/kg of fuel)	7.14
% Excess air	22.8
% Heat loss due to dry flue gas	7.34
% Heat loss due to evaporation of water formed due to H ₂ in fuel	4.55
% Heat loss due to evaporation of moisture present in fuel	2.03
% Heat loss due to moisture present in air	0.19
% Heat loss due to unburnt in fly ash	0.46
% Heat loss due to unburnt in bottom ash	0.39
% Heat loss due to radiation	0.5
Total percent heat loss	15.47
Boiler efficiency	84.52

3.5.3 Correction in air supplied

In WTPS, the air supplied is in three different stages. Primary air is supplied as a mixture with coal. Secondary air is divided in two parts: through the fuel air damper and through auxiliary air damper. To vary the supply of air upto optimum value, secondary air damper is used.

As per analysis of optimum value of excess air done previously, it is known that to improve the efficiency and reduce the heat losses, secondary air dampers are needed to be set for 15%

excess air. Since the excess air before correcting damper position is above 15% excess air, it is needed to close the dampers till optimum value is reached by keeping in view the amount of O₂ in flue gas outlet in Direct Control System.

Correction in fuel air damper

Here, five mills are in service conditions. So total 20 fuel air dampers are open. Now correction in secondary air flow through fuel air dampers after closing dampers upto optimum value of excess air is shown in Table 3.6. As we know the relation between percent of O₂ in flue gas at exit and excess air, we monitor the correction accordingly by gradually closing the dampers.

Table 3.6: Secondary air flow through FAD

SA flow through FAD	220 T/hr
FAD (% open/close)	37% open

Correction in auxiliary air damper

Correction in secondary air flow through auxiliary air dampers after closing dampers upto optimum value of excess air is shown in Table 3.7.

Table 3.7: Auxiliary air damper correction

SA slow through AAD	233 T/hr
AAD (% open/close)	25% open

3.6 Boiler efficiency after correcting damper position.

3.6.1 Coal analysis and other operating parameters

The proximate analysis and ultimate analysis of coal carried out in chemical laboratory is shown in Table 3.8. The operating parameters are shown in Table 3.9.

Table 3.8: Proximate and Ultimate analysis

Proximate Analysis		Ultimate Analysis	
Moisture	12 %	Carbon	43.15 %
Ash	33.76 %	Hydrogen	2.99 %
Volatile Matter	23.07 %	Oxygen	5.78 %
Fixed Carbon	31.17 %	Sulphur	0.5 %
GCV	3850 kcal/kg	Nitrogen	1.82 %
		Moisture	12 %
		Ash	33.76 %

Table 3.9: Operating parameters

Parameters	Values
Flue gas temperature	180 °C
% O ₂ in F.G	3.9
% CO ₂ in F.G	12.85
% CO in F.G	0.005
Dry bulb temperature	29 °C
% Combustible in fly ash	0.81
% Combustible in botom ash	2.8
Humidity factor	0.015
CV of carbon	8084 kcal/kg

3.6.2 Heat losses and Boiler efficiency

Table 3.10 shows heat losses in boiler and boiler efficiency calculated according to “Heat Loss Method”[17].

Table 3.10: Heat losses and Boiler efficiency after correcting damper position

Calculated Parameters	Values
Theoretical air required (kg/kg of fuel)	5.81
Actual air supplied (kg/kg of fuel)	6.69
% Excess air	15
% Heat loss due to dry flue gas	6.52
% Heat loss due to evaporation of water formed due to H ₂ in fuel	2.02
% Heat loss due to evaporation of moisture present in fuel	4.52
% Heat loss due to moisture present in air	0.16
% Heat loss due to unburnt in fly ash	0.48
% Heat loss due to unburnt in bottom ash	0.34
% Heat loss due to radiation	0.5
Total percent heat loss	14.56
Boiler efficiency	85.43

3.7 Results and Discussion

3.7.1 For clean air test

The clean air test with velocity and airflow at each corner is shown in Table 3.11.

Table 3.11: Clean air test showing velocity and airflow at four corners.

PIPE NO	Deviations Limits	Velocity m/s	Airflow T/hr
Corner -1	Actual	21.12	12.05
	Deviations	-19.9	-19.83
Corner -2	Actual	27.31	15.54
	Deviations	3.56	3.39
Corner -3	Actual	28.02	16.01
	Deviations	6.26	6.52
Corner -4	Actual	29.02	16.53
	Deviations	10.05	9.98
MEAN	Average	26.37	15.03
	Total		60.13

The graph of air flow versus corners is shown in Figure 3.7.

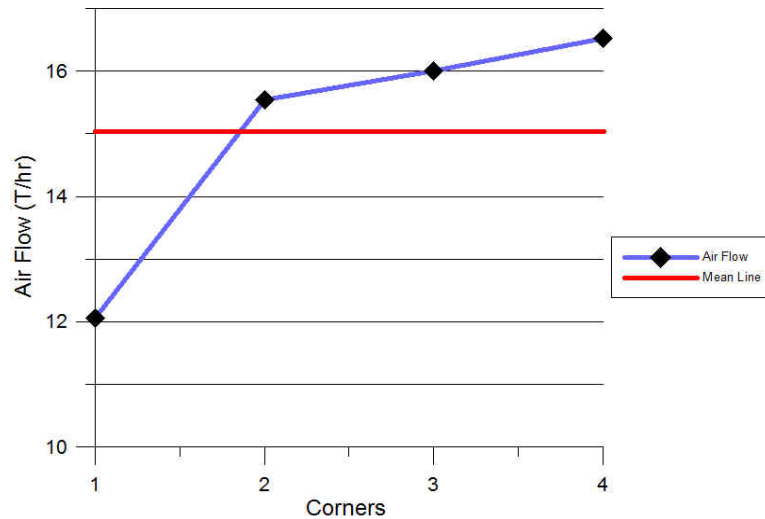


Figure 3.7: Clean Air Flow vs Corners

The observations of deviations for clean air flow is shown in Table 3.12.

Table 3.12: Observation of deviations in clean air test

	Corner-1	Corner-2	Corner-3	Corner-4
Clean Air Velocity	-19.90	3.56	6.26	10.05
Air Flow	-19.83	3.39	6.52	9.98

All the deviations are from mean values(in % only)

Remark:

After carrying out clean air test, it was found that the deviations of air flow at corner no.1, 3 and 4 are not within acceptable limits. So it is needed to check the orifices and arrange for availability of sampling ports at corner no. 1, 3 and 4.

3.7.2 For dirty air test

Table 3.13 shows velocity, air flow, A/F ratio of dirty air test. The graph of air flow versus corners is shown in Figure 3.8.

Table 3.13: Dirty air test

Pipe No	Deviation Limits	Velocity m/s	Air flow T/hr	Fuel Flow T/hr	A/F Ratio
		>18m/s	+/-5%	+/- 10%	1.8 to 2
Corner-1	Actual	32.04	16.31	5.36	3.04
	Deviation	3.08	3.22	-0.19	1.04
Corner-2	Actual	27.38	13.83	4.2	3.2
	Deviation	-11.9	-12.46	-21.78	1.2
Corner-3	Actual	33.21	17.01	6.36	2.67
	Deviation	6.85	7.65	18.4	0.67
Corner-4	Actual	31.69	16.30	5.56	2.93
	Deviation	1.96	3.16	3.53	0.93
MEAN	Average	31.08	15.8	5.37	2.96
	Total		63.45	21.48	11.84

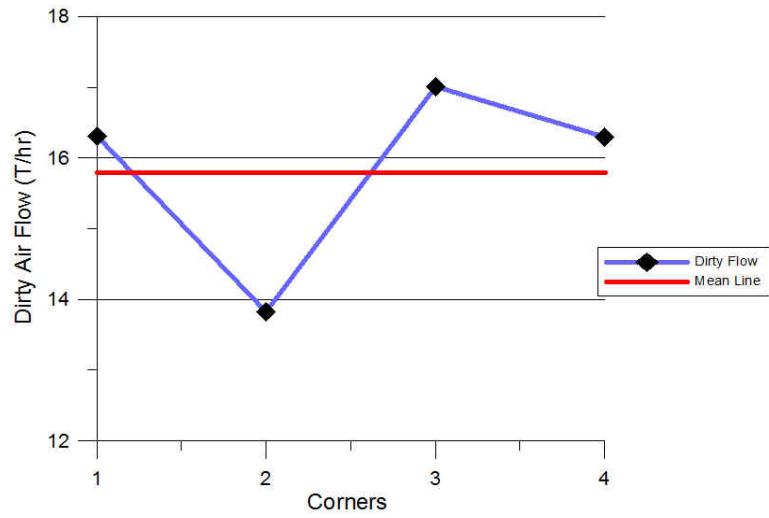


Figure 3.8: Dirty air flow vs Corners

The graph of fuel flow versus corners is shown in Figure 3.9.

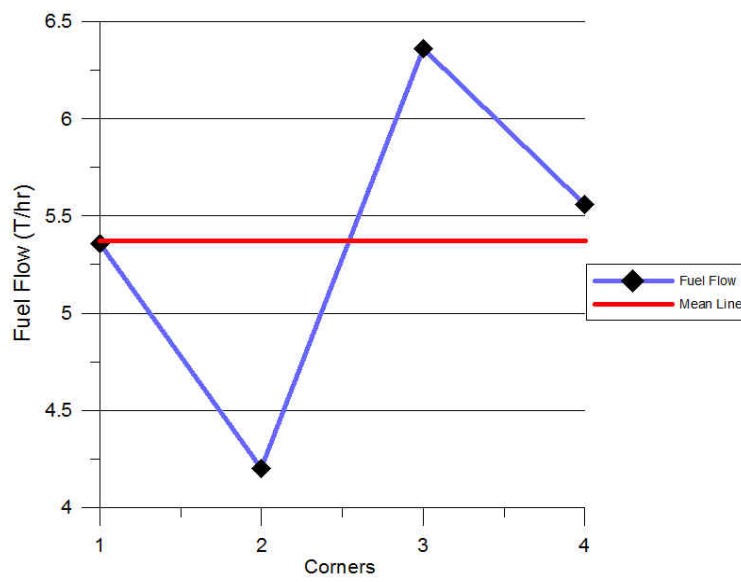


Figure 3.9: Fuel flow vs Corners

The graph of air fuel ratio versus corners is shown in Figure 3.10.

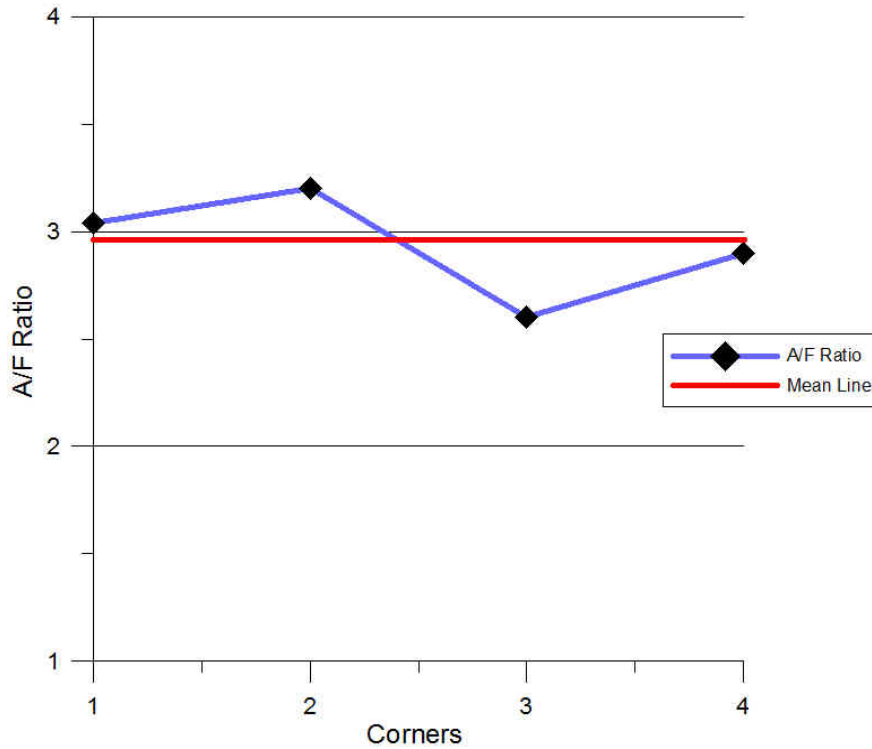


Figure 3.10: A/F Ratio vs Corners

Table 3.14 is showing deviations in observations for dirty air test.

Table 3.14: Observation of deviations in dirty air test

	Corner-1	Corner-2	Corner-3	Corner-4
Air flow	3.22	-12.46	7.65	3.16
Fuel flow	-0.19	-21.78	18.4	3.53

All the deviations are from mean values.

Remark:

After carrying out dirty air test, it was found that the deviations in air flow as well as fuel flow variation at corner 2 and 3 are not within acceptable limits for proper flow balancing. So it is needed to check the orifices and classifier angles properly for even distribution of air fuel supply in furnace.

3.7.3 For secondary air damper

After correcting the damper position upto optimum value of excess air, boiler efficiency improved and heat losses reduced. The fuel air dampers and auxiliary air dampers before correcting damper position were 48% open and 35% open respectively. After correction, the fuel air dampers and auxiliary air dampers were closed upto 37% and 25% respectively. The effect of decreasing excess air to optimum value resulted towards reduction in dry flue gas losses and improved boiler efficiency.

Chapter 4

Economic Analysis of Reheat Spray & Exergy Analysis of Combustion

This chapter includes economic analysis of reheat spray for different burner tilting angle. Also rational efficiency and combustion efficiency of boiler have been calculated using exergy analysis.

4.1 Reheat steam temperature control

In boilers with reheat stages, the temperature of both the reheater and superheater gets affected with change in firing. Steam temperature gets affected by the pattern at which burners are fired since some tubes of boiler pick up heat by direct radiation from boiler. The temperature of steam gets affected by the flow of fluid within tubes and flow of hot gases in boiler. Because of the lower operating pressure of reheat steam system, the thermodynamic conditions are significantly different from those of superheaters, and the injection of spray water into the reheater system has an undue effect on the efficiency of the plant. For this reason, it is preferable for the reheat stage to be controlled by tilting burners.

In boilers with fixed burners, steam temperature control may be achieved by adjusting the opening of dampers that control the flow of furnace gases across the various tube banks. In some cases two separate sets of dampers are provided: one for regulating the flow over the superheater banks, the other controlling the flow over the reheater banks. Between them, these two sets of dampers deal with the entire volume of combustion gases flowing from the furnace to the chimney. If both were closed at the same time, the flow of these gases would be severely restricted, leading to the possibility of damage to the structure due to overpressure.

For this reason, two sets are controlled in a 'split range' style, with one set being allowed to close only when the other has fully opened.

These dampers provide the main form of control, but the response of the system is very slow, particularly with large boilers, where the temperature response to changes in heat input exhibits a lag of almost two minutes duration. For this reason, and also to provide a means of reducing the temperature of reheat steam in event of failure in damper systems, spray attemperation is provided for emergency cooling[19].

Attemperator is a device which reduce the steam temperature to a point which is still above saturation point, while desuperheater is the one that lowers it below saturation point. Boiler designers adopt methods like divided second pass, burner tilting, water injection and gas recirculation to control reheat steam outlet temperature.

4.2 Temperature control using burner tilting

In burner tilting arrangement, the burning fuel forms a large swirling fireball in a corner fired boiler, which can be moved to higher or lower level in the furnace by tilting the burners upwards or downwards with respect to a mid position. The repositioning of fireball changes the pattern of heat transfer to the various banks of superheater tubes and this provides an efficient method of controlling the steam temperature, since it enables the use of spray water to be reserved for emergency purposes and fine tuning purposes.

With boilers having burner tilting arrangement, the steam temperature control systems become significantly different from those of boilers with fixed burners. The boiler designer is able to define the optimum angular position of the burners for all loads, and the control engineer can then use a function generator to set the angle of tilt over the load range to match this characteristics. A temperature controller trims the degree of tilt so that the correct steam temperature is attained[20].

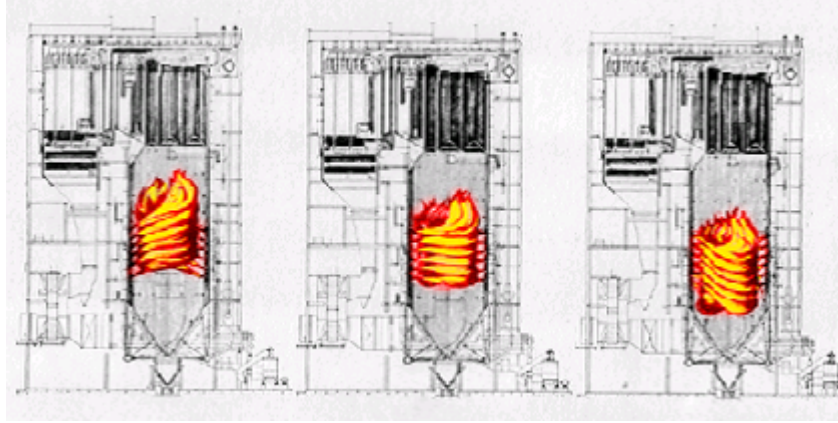


Figure 4.1: Burner tilting positions[16]

In tangential fired furnace, burner tilting are generally used. The different position of burner is shown in Figure 4.1. When the reheat steam temperature is above the rated value, the burner move downwards which reduces the heat absorbtion and temperature starts to reduce. On other hand when steam temperature is below the rated value, the burner moves upwards.

4.3 Economic analysis of reheat spray

The following table shows economic analysis of reheat spray in burner tilting. The effect of reheat spray at different positions in burner tilting is shown in Table 4.1.

Table 4.1: Effect of Reheat spray in burner tilting

Burner Tilting Position	Coal firing (T/hr)	R.H Outlet Temp. (°C) Before spray	R.H spray (T/hr)	R.H Outlet Temp. (°C) After Spray	Economic loss/gain w.r.t horizontal position (Rs./day)	% Economic loss/gain w.r.t horizontal position
20	149	540	23	535	32200.77	-43.7
15	148	539	22	535	27616.44	-37.5
10	147	539	20	535	18392.55	-24
5	145.7	538	18	535	9168.66	-12.4
0	145	536	16	535	73625.42	0
-5	144.5	533	15	535	4584.32	6.2
-10	143	532	11	535	22976.88	31.2
-15	142.6	528	8	535	36785.1	49.9
-20	141	526	2	535	64401.53	87.47

Calculations for economic loss when burner tilting is set at 0° horizontal position is calculated as follows:

For Increase in R.H spray by 6 T/hr., increase in heat rate is 5 kcal/kwh. So with increase in R.H spray by 16 T/hr, increase in heat rate will be 13.33 kcal/kwh.

$$\begin{aligned}
 &\text{Now, at full load} \\
 &= 210 \text{ (kW)} \times 1000 \times 13.33 \text{ (kcal/kwh)} \\
 &= 2799300 \text{ kcal/hr} \\
 &= 2799300 / 3650 \text{ (Calorific value=3650 kcal/kg)} \\
 &= 766.93 \text{ kg/hr} \\
 &= 0.76712 \text{ T/hr} \\
 &= 18.40 \text{ T/day}
 \end{aligned}$$

Due to RH spray at 0° burner tilting angle, excess 18.41 T/Hr coal has to be supplied accordingly if we consider cost of 1 tonne of coal is Rs. 4000, then economic loss of Rs.73625.42 per day will take place.

Similarly economic analysis for different burner tilting position have been calculated and tabulated. Figure 4.2 shows percent economic gain at different position of burner tilting.

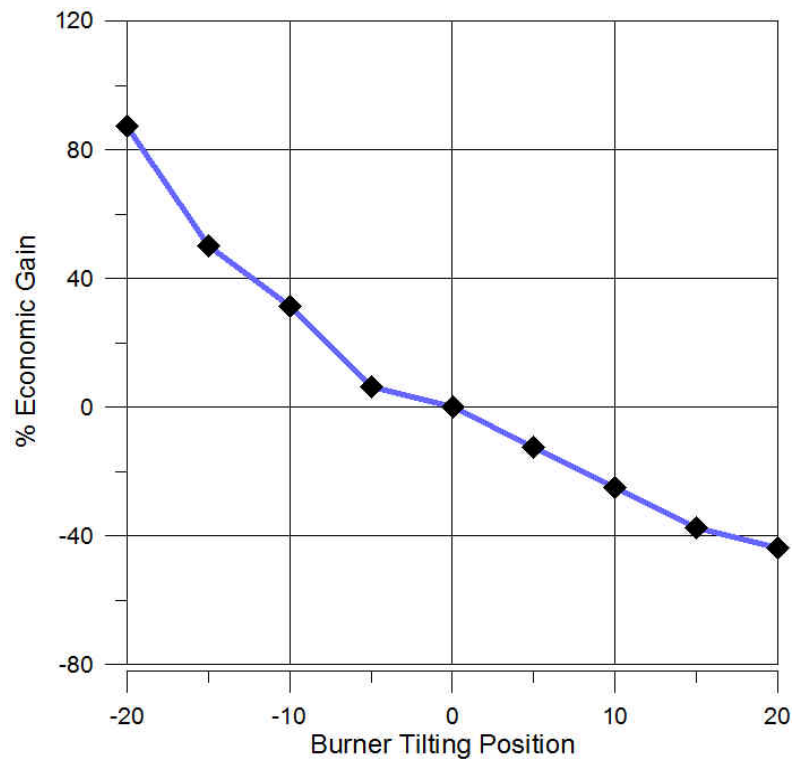


Figure 4.2: % Economic gain at different burner tilting position

From the above figure of economic analysis of reheat spray in burner titlting with respect to horizontal position, it can be concuded that economic gain takes place below the horizontal position of burner tilting due to reduction in reheat spray and economic loss takes place above the horizontal position of burner tilting. So, optimum position of burner tilting is below the horizontal position with respect to reduction in reheat spray.

4.4 Exergy

There are two groups of source of energy, one is high grade energy and another is low grade energy. Examples of high grade energy are mechanical work, electrical energy, water power, wind power, kinetic energy of jet etc. Examples of low grade energy are heat or thermal energy, heat derived from nuclear fission or fusion and heat derived from combustion of fossil fuels. The conversion of high grade energy to shaft work is exempt from the limitations of the second law, while conversion of low grade energy is subject to them. The bulk of high grade energy in the form of mechanical work or electrical energy is obtained from sources of low grade energy, through the medium of cyclic heat engines. The complete conversion of low grade energy into high grade energy is impossible by the virtue of second law of thermodynamics. That part of low grade energy which is available for conversion is referred as available energy, while the part which, according to the second law, must be rejected is known as unavailable energy[2].

Exergy is the maximum useful work obtainable from a system as it reaches the dead state. While energy is always conserved, exergy is not generally conserved, but is destroyed by irreversibilities. Exergy is always destroyed and not conserved when work is done; therefore exergy input is always higher than exergy output. The exergetic efficiency from a thermodynamic point of view gives an accurate measurement of the performance of system.

4.5 Forms of exergy

There are four types of exergy as follows[21]:

- 1) Kinetic exergy
- 2) Potential exergy
- 3) Physical exergy
- 4) Chemical exergy

Kinetic & Potential Exergy

The kinetic and potential energy of a system are ordered forms of energy and so it is completely convertible to work. Therefore, when evaluated in relation to the environmental

reference datum levels, they are equal to kinetic and potential exergy.

Kinetic exergy:

$$\dot{E}_k = \dot{m} \frac{V_0^2}{2}$$

where \dot{m} is the mass flow rate of fluid stream, V_0 is the velocity of the system relative to the environment.

Potential exergy:

$$\dot{E}_p = \dot{m} g Z_0$$

where g is gravitational acceleration and Z_0 is altitude of stream above the sea level.

Physical Exergy

Physical exergy is equal to the maximum amount of work obtainable when the stream of substance is brought from its initial state to the environmental state defined by P_0 and T_0 , by physical processes involving only thermal interaction with environment.

Physical exergy = thermal component of physical exergy + pressure component of physical exergy

Chemical Exergy

Chemical exergy is equal to the maximum amount of work obtainable when the substance under consideration is brought from the environmental state to the dead state by processes involving heat transfer and exchange of substances only with the environment.

A technique for calculating the standard chemical exergy is shown in below section.

4.6 Chemical processes including combustion

Before exergy analysis, mass and energy balance on the system are required to be carried out to determine flow rate and energy transfer rate at the control surface, then follows exergy analysis. Figure 4.3 shows an open system undergoing a steady flow process involving one or more chemical reactions.

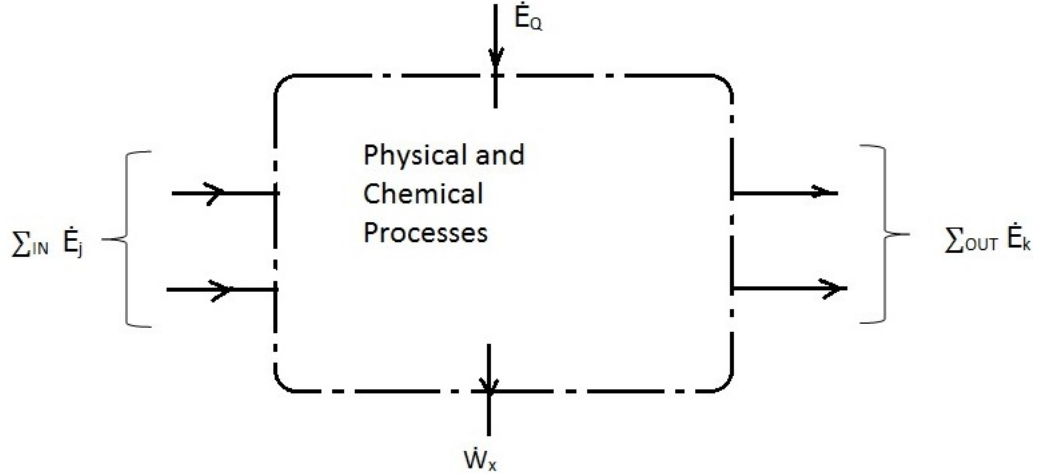


Figure 4.3: Control region of reacting open system[21]

The exergy balance for such a system in its basic form is essentially the same as for an open system undergoing physical process and can be written in form as given below.

$$\sum_{in} \dot{E}_j + \dot{E}_Q = \sum_{out} \dot{E}_k + W_x + I$$

$$\sum_{in} \dot{E}_j - \sum_{out} \dot{E}_k = -\dot{E}_Q + W_x + I$$

where subscripts j and k refers to stream entering and leaving control region.

\dot{E}_Q is exergy associated with heat transfer and W_x refers to exergy associated with work transfer.

In open system under consideration the chemical composition of stream entering the control region is different from those leaving it, so the exergy values of each substance must be based on the system of reference substances. Using this scheme, exergy rate of stream of substance (neglecting potential and kinetic components) can be written in the form as below.

$$\dot{E} = \dot{E}_{ph} + \dot{E}_o$$

Hence using molar quantities, the L.H.S of exergy balance balance given in above form is

$$(\sum_{in} \dot{n}_j \dot{e}_{ph,j} - \sum_{out} \dot{n}_k \dot{e}_{ph,k}) + (\sum_{in} \dot{n}_j \dot{e}_{o,j} - \sum_{out} \dot{n}_k \dot{e}_{o,k})$$

allowing the chemical and physical changes in exergy of streams of matter to be dealt with separately.

4.6.1 Chemical components of exergy

A simple combustion process is an exothermic chemical reaction, reactants are usually air and fuel and products mainly mixture of common environmental substance.

Chemical exergy for solid fuel

For dry organic substances contained in solid fossil fuel, consisting of C, H, O & N with a mass ratio of oxygen to carbon less than 0.667, the following expression is to be used in terms of mass ratio.

$$\Phi_{dry} = 1.0437 + 0.1882 \frac{h}{c} + 0.0610 \frac{o}{c} + 0.0404 \frac{n}{c}$$

where c, h, o, & n are mass fractions of C, H, O & N respectively.

For fossil fuels with mass ratios $2.67 > o/c > 0.667$ which in particular includes wood, following expression is used.

$$\Phi_{dry} = (1.0438 + 0.1882 \frac{h}{c} - 0.2509(1 + 0.7256 \frac{h}{c}) + 0.0383 \frac{n}{c}) / (1 - 0.3035 \frac{o}{c})$$

Chemical exergy of solid industrial fossil fuel is given by

$$\varepsilon^o (\text{KJ/kg}) = [(NCV)^o + 2.442w] \Phi_{dry} + 9.417s$$

where NCV is net calorific value, w = mass fraction of moisture in fuel, s = mass fraction of sulphur in fuel.

Szargut & Strylska assumed that the ratio of chemical exergy to net calorific value for solid & industrial fuels is same as for pure chemical substance having same ratios of constituent chemicals. This ratio is denoted by Φ . Typical values of Φ for different types of coal should be in the range of 1.06 to 1.10 [21].

$$\Phi = \frac{\varepsilon^o}{(NCV)^o}$$

4.6.2 Physical components of exergy

The most general definition of physical exergy can be expressed in molar form as:

$$\dot{\varepsilon}_{ph} = (\hat{h} - \hat{h}_o) - T_o(\hat{s} - \hat{s}_o)$$

which can be used with suitable property tables when considering, for example steam, water and other liquids and solids. For an ideal gas, above equation may be conveniently expressed in terms of the thermal component and the pressure component as:

$$\dot{\varepsilon}_{ph} = \hat{C}_p \dot{\varepsilon} (T - T_o) + \dot{R} T_o \ln \left(\frac{P}{P_o} \right)$$

$$\text{where } \hat{C}p^\varepsilon = \frac{\varepsilon \Delta T}{T - T_o}$$

$$\hat{C}p^\varepsilon = \frac{1}{T - T_o} \left[\int \hat{C}_p dT - T_o \int (\hat{C}_p dT / T) \right]$$

$\hat{C}p^\varepsilon$ may be looked as mean, molar isobaric exergy capacity.

Calculation of the thermal component of physical exergy is simplified by using tabulated values of mean specific heat capacities. Two forms of mean specific heat capacity may be expressed, one for enthalpy and other for entropy evaluation.

$$\hat{C}p^h = \frac{1}{T - T_o} \int (\hat{C}_p dT)$$

$$\hat{C}p^s = \frac{1}{T - T_o} \int (\hat{C}_p dT / T)$$

From above equations of $\hat{C}p^\varepsilon$, $\hat{C}p^h$ and $\hat{C}p^s$

$$\dot{\varepsilon}_{ph} = \hat{C}p^h (T - T_o) - T_o \hat{C}p^s \ln\left(\frac{T}{T_o}\right) + \dot{R} T_o \ln\left(\frac{P}{P_o}\right)$$

Values for mean specific heat capacity are tabulated in Appendix C for the standard temperature over a range of values of T for several common gases. The tabulated values are also useful in energy balances in conjunction with enthalpy of devaluation.

4.7 Exergy Analysis

In a coal fired power plant, bituminous coal is used as fuel. Both the air and fuel are assumed to be delivered at standard pressure and temperature. In Figure 4.4 shown below, I shows sub region of combustion, II shows sub region of heat transfer and III shows sub region of mixing of products of combustion with ambient air.

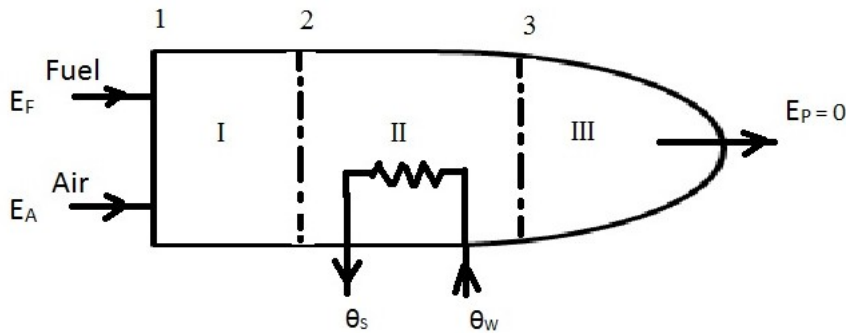


Figure 4.4: Coal fired plant[21]

The composition of bituminous coal by mass is shown in Table 4.2. Assuming no heat losses and pressure losses, exergy analysis is carried out as follows[21]:

Table 4.2: Composition of Bituminous by mass

Carbon	0.4315
Hydrogen	0.0299
Nitrogen	0.0182
Sulphur	0.005
Oxygen	0.0578
Moisture	0.12
Ash	0.3376
NCV in kJ/kg	16795

Now according to chemical exergy technique mentioned earlier, standard chemical exergy is calculated below:

For dry organic substances contained in solid fossil fuel, consisting of C, H, O & N with a mass ratio of oxygen to carbon less than 0.667, the following expression is to be used in terms of mass ratio.

$$\Phi_{dry} = 1.0437 + 0.1882 \frac{h}{c} + 0.0610 \frac{o}{c} + 0.0404 \frac{n}{c}$$

$$\text{So, } \Phi_{dry} = 1.0437 + 0.1882 \left(\frac{0.0299}{0.4315} \right) + 0.0610 \left(\frac{0.0578}{0.4315} \right) + 0.0404 \left(\frac{0.0182}{0.4315} \right)$$

$$\Phi_{dry} = 1.0437 + 0.01304 + 0.00817 + 0.0017$$

$$\Phi_{dry} = 1.066$$

$$\text{Now, standard chemical exergy, } \varepsilon^o (\text{kJ/kg}) = [(NCV)^o + 2.442w] \Phi_{dry} + 9.417s$$

$$\varepsilon^o = [(16795 + (2.442 \times 0.12))] 1.066 + (9.417 \times 0.005)$$

$$\varepsilon^o = 18273.35 \text{ kJ/kg}$$

$$\text{So, ratio of industrial fuel, } \Phi = \frac{\varepsilon^o}{(NCV)^o}$$

$$\Phi = \left(\frac{18273.35}{16795} \right) = 1.088$$

Now, a mass balance shows the composition of the products of combustion as follows:

Table 4.3: No of moles and mole fraction of products of combustion

	CO_2	H_2O	SO_2	O_2	N_2
n_k (kmol/100 kg fuel)	3.595	1.495	0.18062	1.498	19.558
x_k	0.1365	0.0567	0.0068	0.0569	0.7429

Calculation of θ_2 :

Assuming, coal and air enter the adiabatic combustion space at T^o and P^o , energy balance may be written as following:

$$m_f (NCV)^o = (\theta_2 - \theta^o) \sum n_k (\hat{C}_p^h)_k$$

The sum of $\sum n_k(\hat{C}_p^h)_k$ can be determined from values of \hat{C}_p^h extracted from Appendix for a trial value of θ_2 . The iteration procedure gives following value of \hat{C}_p^h corresponding to values of θ_2 .

Considering $\theta = 1550^\circ\text{C}$, the following Table 4.4 shows value of \hat{C}_p^h for products of combustion.

Table 4.4: Value of \hat{C}_p^h for products of combustion.

	CO_2	H_2O	SO_2	O_2	N_2
\hat{C}_p^h (kJ/kmol)	53.24	40.78	52.57	34.35	32.69

$$\text{Now, } \sum n_k(\hat{C}_p^h)_k = 3.595(53.24) + 1.495(40.78) + 19.558(32.69) + 1.498(34.35) + 0.18062(52.57)$$

$$\sum n_k(\hat{C}_p^h)_k = 1006.65 \text{ kJ/K}$$

$$\text{So } \theta_2 = \theta^\circ + (m_f(NCV)^\circ / \sum n_k(\hat{C}_p^h)_k)$$

$$\theta_2 = 25 + ((100 \times 16795) / 1006.65)$$

$$\theta_2 = 1693.3^\circ\text{C}$$

The combustion temperature in combustion region ranges from 1300°C - 1700°C . Now the values of θ_2 decreases upto 1693.3°C for $\theta = 1550^\circ\text{C}$, then it increases. So, we will consider $\theta_2 = 1693.3^\circ\text{C}$ for $\theta = 1550^\circ\text{C}$.

Irreversibility in combustion region[21]

Since $E^\circ = 0$, $W = 0$ and $(E^\circ)_{air} = 0$, the irreversibility in combustion region is written as

$$I_1 = E_F - E_2, \text{ where } E_F = m_F (\varepsilon^\circ)_F$$

$$E_2 = n_{p2}(\varepsilon^\circ)_p + \sum n_k(\dot{\varepsilon}_{ph})$$

$$\text{where, } (\varepsilon^\circ)_p = \sum n_k(\varepsilon^\circ)_k + \dot{R}T_o \sum (n_k \ln x_k)$$

From Appendix B, the value of standard chemical exergy for products of combustion are obtained as follows:

Table 4.5: Value of standard chemical exergy of product of combustion

	CO_2	H_2O	SO_2	O_2	N_2
ε° (kJ/kmol)	20140	11710	303500	3970	720

$$\text{Now, } (\varepsilon^\circ)_p = \sum n_k(\varepsilon^\circ)_k + \dot{R}T_o \sum (n_k \ln x_k)$$

$$(\varepsilon^\circ)_p = 6237.64 + 2478.81(-0.2718 - 0.1627 - 0.2207 - 0.1631 - 0.3393)$$

$$(\varepsilon^\circ)_p = 6237.64 - 2112.83 = 4124.7 \text{ kJ/mol}$$

Now, the physical component of exergy of product is evaluated using data extracted from Appendix C for isobaric exergy capacity \hat{C}_p^ε .

Table 4.6: Value of $\hat{C}p^\epsilon$ for products of combustion

	CO_2	H_2O	SO_2	O_2	N_2
$\hat{C}p^\epsilon$ (kJ/kmol K)	35.49	26.91	34.83	22.60	21.46

$$\text{So, } \sum n_k(\dot{\epsilon}_{ph}) = (\theta_2 - \theta^o) \sum n_k \hat{C}p^\epsilon$$

$$\text{where } \sum n_k \hat{C}p^\epsilon = (3.595 \times 35.49) + (1.495 \times 26.91) + (19.558 \times 21.46) + (1.498 \times 22.60) + (0.1806 \times 34.83)$$

$$\sum n_k \hat{C}p^\epsilon = 627.67 \text{ kJ/K}$$

$$\text{Hence, } \sum n_k(\dot{\epsilon}_{ph}) = (1693 - 25) \times 627.67 = 1046953.5 \text{ kJ}$$

$$\text{Also, } E_2 = (26.326 \times 4124.7) + 1046953.5 = 1155540.3 \text{ kJ}$$

Substituting calculated values of exergy terms in I_1 .

$$I_1 = (100 \times 16795) - 1155540.3 = 523959.7 \text{ kJ per 100 kg of fuel.}$$

Irreversibility in heat transfer region[21]

Mass of H_2O , m corresponding to given operating conditions i.e $\theta_w = 150^\circ\text{C}$ and $\theta_s = 540^\circ\text{C}$, can be calculated from energy balance

$$H_2 - H_3 = m_s(h_s - h_w).$$

Now at given operating conditions, from steam table we get $h_s = 3394 \text{ kJ/kg}$ & $h_w = 644.5 \text{ kJ/kg}$

$$\text{So, } H_2 = 983.97 \times (1693 - 25) = 1641261.9 \text{ kJ}$$

H_3 will be calculated from $\hat{C}p^h$ values extracted from Appendix C.

Table 4.7: Value of $\hat{C}p^h$ for combustion products

	CO_2	H_2O	SO_2	O_2	N_2
$\hat{C}p^h$ (kJ/kmol K)	41.52	33.93	42.88	29.50	29.59

$$\text{So, } H_3 = (\theta_3 - \theta^o) \sum n_k(\hat{C}p^h)_k$$

$$H_3 = 175 \times 1090.5 = 190850.2 \text{ kJ}$$

Substituting numerical values in mentioned above energy balance equation

$$m_s = \left(\frac{1641261.9 - 190850.2}{3394 - 644.5} \right) = 527.5 \text{ kg}$$

$$\text{Also, Irreversibility } I_2 = (E_2 - E_3) - (E_s - E_w)$$

$$\text{where, } (E_s - E_w) = m_s[(h_s - h_w) - T^o(s_s - s_w)]$$

Now, for water substance, $s_s = 6.337 \text{ kJ/kgK}$, $s_w = 1.821 \text{ kJ/kgK}$

$$(E_s - E_w) = 527.5 \times [(3394 - 644.5) - 298.15(6.337 - 1.821)]$$

$$(E_s - E_w) = 740111.3 \text{ kJ}$$

E_3 will be calculated from following data obtained from Appendix C at 200°C .

Table 4.8: Values of \hat{C}_p^ϵ for combustion products

	CO_2	H_2O	SO_2	O_2	N_2
\hat{C}_p^ϵ (kJ/kmol K)	9.09	7.22	9.31	6.45	6.34

Now, $(E_{ph})_p = (\theta_3 - \theta^o) \sum n_k \hat{C}_p^\epsilon$

$$(E_{ph})_p = 175 \times 178.81 = 31292.4 \text{ kJ}$$

$$\text{And } E_3 = (26326 \times 41247) + 31292.4 = 139879.2 \text{ kJ}$$

Now, substituting above values in $I_2 = (E_2 - E_3) - (E_s - E_w)$

$$I_2 = (1155540.3 - 139879.2) - 740111.3$$

$$I_2 = 275549.8 \text{ kJ}$$

Rational efficiency of boiler

$$\text{Hence, rational efficiency of boiler, } \Psi = \frac{(E_s - E_w)}{E_f} = \frac{740111.3}{1827335} = 0.405 = 40.5\%$$

This value may be compared with conventional boiler efficiency known as combustion efficiency.

$$\text{Combustion efficiency, } \eta_c = \frac{m_s(h_s - h_w)}{m_f(NCV)^o} = \frac{527.5(3394 - 644.5)}{100(16795)} = 0.863 = 86.3\%$$

Chapter 5

Conclusion and Future Scope of Work

5.1 Conclusion

1. Optimization of combustion in pulverised coal fired boiler resulted into reduction in heat losses in boiler and improvement in boiler efficiency. The heat losses in the boiler before optimization was 15.47% which reduced to 14.56% after correcting damper position. Similarly, boiler efficiency before optimization was 84.52% which improved to 85.43% after correcting damper position.
2. After economic analysis of reheat spray in burner tilting, we came into conclusion that economic benefit takes place due to reduction in reheat spray in downward position of burner tilting. So, optimum position of burner tilting is below the horizontal position which leads to reduction in reheat spray.
3. Exergy analysis of combustion process resulted into rational efficiency of boiler as 40.5% and combustion efficiency as 86.3%.

5.2 Future Scope of Work

1. A predictive modeling of NO_x emission of 210 MW coal fired plant with the help of artificial neural network can be proposed. Under full load operation, the predicted model can be verified with actual values using back propagation feed forward neural network.
2. A mathematical modeling of a combustion process can be developed to optimize combustion which can be solved numerically using simulation tool like Computational Fluid Dynamics (CFD).

Bibliography

- [1] Raja A.K., Amit Prakarsh, Manish Dwivedi, “Power Plant Engineering”, New Age International Publishers, 3rd Edition, Chapter 4, 2006.
- [2] Nag P.K., “Power Plant Engineering,” Tata McGraw-Hill, 3rd Edition, Chapter 4, 2008.
- [3] “Familiarization of GSECL Power Plant”, GSECL, 2nd Edition; Page No. 15; 2014.
- [4] Benyuan Huang, Zixue Luo and Huaichun Zhou, “Optimization of combustion based on introducing Radiant Energy Signal (RES) in pulverized coal fired boiler”, Fuel Processing Technology 91 (2010), 660-668.
- [5] REN Jianxing, LI Fangqin, Zhu Qunzhi, Wu Jiang, “Research of Multi Fuel burning stability in 300 MW Coal fired utility boiler”, Energy Procedia 17 (2012), 1242-1248.
- [6] Ji-Zheng Chu, Shyan Shu, Shieh, Shi- Shang Jang, “Constrained optimization of combustion in simulated coal fired boiler using artificial neural network model and information analysis”, Fuel 82 (2003), 693-703.
- [7] Feng Wu, Hao Zhou, Jia-Pei Zhao, Ke-Fa Chan, “A comparative study of multi objective optimization algorithms for coal fired boiler”, Expert Systems with Applications 38 (2011), 7179-7185.
- [8] Barry E. Pulskamp, Patrick H. McGowan, Richard F. Storm, “Pulverised coal boiler optimization through fuel air control”, Coal Utilization Conference 87 (1991), 1-16.
- [9] Li Gang Zheng, Hao Zhou, Kef a Cen, Chaun Lin Wang, “A Comparative study of optimization algorithms for low NOx combustion modification at a coal fired utility boiler”, Expert Systems with Applications 36 (2009), 2780-2793.
- [10] Ilamathi P, Selladurai V, Balamurugan K, “Predictive modelling and optimization of power plant nitrogen oxides emission”, Artificial Intelligence (2012), 11-18.

- [11] Hao Zhou, Kefa Cen, Jianren Fan, “Modelling and optimization of the NO_x emission characteristics of a tangentially fired boiler artificial neural networks”, *Energy* 29 (2004), 167-183.
- [12] Risto V Filkoski, Ilija J Petrovski & Piotrkaras, “Optimisation of pulverised coal combustion by means of CFD/CTA modelling”, Volume 10 (2006), 161-179.
- [13] Powermag, ([https://www.powermag.com/pulverised coal flow balancing](https://www.powermag.com/pulverised-coal-flow-balancing))
- [14] Innovation Combustion Technologies, ([https://www.innovationcombustion.com/fuel sampling standard](https://www.innovationcombustion.com/fuel-sampling-standard))
- [15] West Bengal Power Development Corporation Ltd, ([https://www.wbpdclwef.org.in/mill dirty air flow](https://www.wbpdclwef.org.in/mill-dirty-air-flow))
- [16] RLA Report for Wanakbori Thermal Power Station, BHEL Tituchirapalli, 2012.
- [17] “Energy Efficiency in Thermal Utilities”, Bureau of Energy Efficiency, Chapter 2.
- [18] Gill A.B., “Power Plant Performance”, Butterworths Publishers, 2006.
- [19] David Lindsley, “Power plant control and instrumentation”, IET, Chapter 7, 2000.
- [20] Brighthub Engineering, ([https://brighthubengineering/reheat temperature control in boiler/](https://brighthubengineering/reheat-temperature-control-in-boiler/))
- [21] Kotas, “The Exergy method of thermal plant analysis”, Kreiger Publishing Company, Chapter 4, 1995.

Appendix A

Analysis of Optimum value of excess air

Table A.1: Parameters for different excess air supply

Parameter	Excess Air							
	0	5	10	15	20	25	30	35
% O_2 in F.G	0.00	1.00	1.91	2.74	3.50	4.20	4.85	5.44
% CO_2 in F.G	18.47	17.59	16.79	16.06	15.39	14.78	14.21	13.68
Exhaust temp.	125	131	135	141	145	151	157	162
Specific humidity	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
DBT	38	38	38	38	38	38	38	38

Table A.2: Heat losses for different excess air supply

Heat losses	Excess Air							
	0	5	10	15	20	25	30	35
Dry gas loss	3.75	4.24	4.56	5.05	5.52	6.02	6.54	7.08
Combustible in ash	1.11	1.14	1.15	1.19	1.22	1.25	1.29	1.31
H_2 in coal	4.30	4.33	4.34	4.36	4.38	4.39	4.41	4.43
Moisture in fuel	1.12	1.12	1.13	1.134	1.14	1.143	1.15	1.152
Moisture in air	0.11	0.13	0.14	0.16	0.17	0.19	0.21	0.22
Incomplete combustion loss	14.31	10.67	4.65	0.31	0.23	0.22	0.21	0.21
Radiation loss	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Unaccounted loss	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Table A.3: Total heat loss & boiler efficiency at various excess air supply

Excess Air	Total Heat Loss	Boiler Eff.
0	25.40	74.59
5	22.34	77.66
10	16.67	83.32
15	12.90	87.09
20	13.36	86.63
25	13.91	86.08
30	14.52	85.48
35	15.11	84.88

Appendix B

Standard Chemical exergy for various chemical elements

For general application to chemical processes and to processes involving chemical interaction with environment, a system of reference substances originally devised by Szargut and his co-workers is most convenient. Values of standard chemical exergy for various chemical elements have been tabulated at $P_0=1.01325$ bar and $T_0=298.15$ K.

Substance	Standard Chemical Exergy, ε^o (kJ/kmol)
CO	275430
CO_2	20140
H_2O	11710
N_2	720
NO	89040
NO_2	56220
O_2	3970
SO_2	303500
SO_3	225070

Appendix C

Mean heat capacity & exergy capacity of some gases.

Table C.1: Mean molar heat capacity of some gases					
	\hat{C}_p^h (kJ/kmol K)				
θ ($^{\circ}\text{C}$)	N_2	O_2	CO_2	H_2O	SO_2
100	29.32	27.95	39.27	33.35	41.24
200	29.59	29.50	41.52	33.93	42.88
300	29.86	30.52	43.31	34.50	44.33
400	30.13	31.26	44.79	35.06	45.62
500	30.38	31.82	46.04	35.60	46.75
600	30.63	32.26	47.13	36.14	47.74
700	30.88	32.63	48.08	36.67	48.60
800	31.11	32.93	48.92	37.19	49.35
900	31.34	33.20	49.68	37.70	49.99
1000	31.57	33.43	50.37	38.20	50.55
1100	31.79	33.63	50.99	38.69	51.02
1200	32.00	33.82	51.56	39.17	51.44
1300	32.20	33.99	52.09	39.64	51.80
1400	32.40	34.14	52.57	40.11	52.12
1500	32.60	34.28	53.03	40.56	54.42
1550	32.69	34.35	53.24	40.78	52.57
1600	32.78	34.42	53.45	41.00	52.71

Table C.2: Mean exergy capacity of some gases.

θ ($^{\circ}\text{C}$)	$\hat{C}p^{\varepsilon}$ (kJ/kmol K)				
	N_2	O_2	CO_2	H_2O	SO_2
200	6.34	6.45	9.09	7.22	9.31
300	8.76	9.14	13.03	10.09	13.24
400	10.71	11.33	16.34	12.45	16.53
500	12.33	13.13	19.17	14.46	19.36
600	13.71	14.66	21.63	16.21	21.80
700	14.92	15.97	23.80	17.76	23.94
800	15.98	17.11	25.72	19.17	25.82
900	16.94	18.11	27.44	20.45	27.49
1000	17.80	19.00	29.00	21.63	28.96
1100	18.59	19.80	30.41	22.73	30.28
1200	19.31	20.52	31.71	23.75	31.46
1300	19.98	21.18	32.89	24.72	32.53
1350	20.30	21.49	33.45	25.18	33.03
1400	20.60	21.79	33.99	25.63	33.51
1450	20.90	22.07	34.51	26.07	33.96
1500	21.18	22.34	35.01	26.49	34.40
1550	21.46	22.60	35.49	26.91	34.83
1600	21.72	22.85	35.95	27.31	35.24
1650	21.98	23.10	36.40	27.71	35.65
1700	22.23	23.33	36.84	28.09	36.04