OPTIMIZATION OF SOOT BLOWING OPERATION FOR LAKVIJAYA COAL POWER PLANT IN SRI LANKA

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Prof. R.A. Attalage

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ABSTRACT

An optimization of soot blowing operation was carried out for Unit No.3 for Lakvijaya Power Plant in Sri Lanka. Average coal flow rate and flue gas temperature are the key indicators of boiler performance with soot blowing process. In accordance with ASMI PTC 4-1998, a mathematical modeling tool was developed to determine the boiler efficiency in present condition and different frequencies of soot blowing. The maximum efficiency of the boiler was determined as 79.76% at soot free condition. An equation was derived to express the relationship between input fuel consumption and soot blowing frequency. Maximum fuel cost saving can be achieved in between the frequency of 24 hours and 34 hours with respect to the normal operation of routing of soot blowing. Same frequency range gives the maximum cost saving in terms of effective cost. Considering the practical applicability daily soot blowing schedule is recommended.

Key Words: Soot blowing, Boiler performance, Flue gas temperature, Mathematical modeling.

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LIST OF ABBREVIATIONS

APH	Air Preheater
CFD	Computational Fluid Dynamics
LVPP	Lakvijaya Power Plant
DA	Dry Air
DCS	Distributed Control System
GCV	Gross calorific Value
HHVF	Higher Heating Value of Fuel
LRSB	Long Retractable Soot Blower
PSO	Particle Swarm Optimization
RO	Reverse Osmosis
RSB	Rotary Soot Blower
WA	Wet Air

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CHAPTER 1. INTRODUCTION

1.1. Background

Lakvijaya Power Plant (LVPP) is the largest power station in Sri Lanka which is producing average 42% of energy to the national grid daily on average. The power station is located in Norochcholai, Puttalam, on the southern end of Kalpitiya Peninsula. In the plant, basically the electricity is produced using three identical steam turbines which are capable of producing 300 MW from each. Coal is used as the fuel in the purpose of producing high pressure steam in order to rotate the turbine at a speed of 3000 rpm. Since raw coal used at loading stage is in comparatively large size, it is required to pulverize coal for better combustion. For that purpose five mills are used in the LVPP .Thus the energy formed by the burning coal is converted to electrical energy.

1.2. Basic structure of boiler

The boiler is a suspended steel frame structure and also known as bituminous coal-fired drum boiler with subcritical parameters. Main characteristics of the boiler are natural circulation; primary intermediate reheating; corner firing and dry ash extraction. The whole boiler is arranged as a reverse "μ" shape, with a fixed expansion center. The membrane wall is the outer parts of the boiler which consists with two parts known as upper membrane wall and high heat load zone with rifled tube. Dimensions of the furnace section are 14,048 × 11,858 mm, and the centerline elevation of roof tube is 59,300 mm, and the elevation of drum centerline is 63,290 mm.

Three main zones of the boiler system are furnace area, convection pass and back pass zone. Superheater, Reheater are located in the convection pass while back pass zone is consisting with the economizer.

Superheated steam temperature is regulated by attempertor, and reheated steam temperature is regulated by based on tilt of the burner. The tilt angle of the burner can swing ± 30 °up and down. In the furnace area there are total of 12 oil guns in three layers which are used to plant startup and shutdown. The oil ignition device is equipped with a retractable high energy ignition, which could ignite fuel oil directly. The air nozzle of oil ignition burner is also used as a secondary air nozzle for pulverized coal combustion. Figure 1.1 shows the inside view of the boiler during a maintenance.

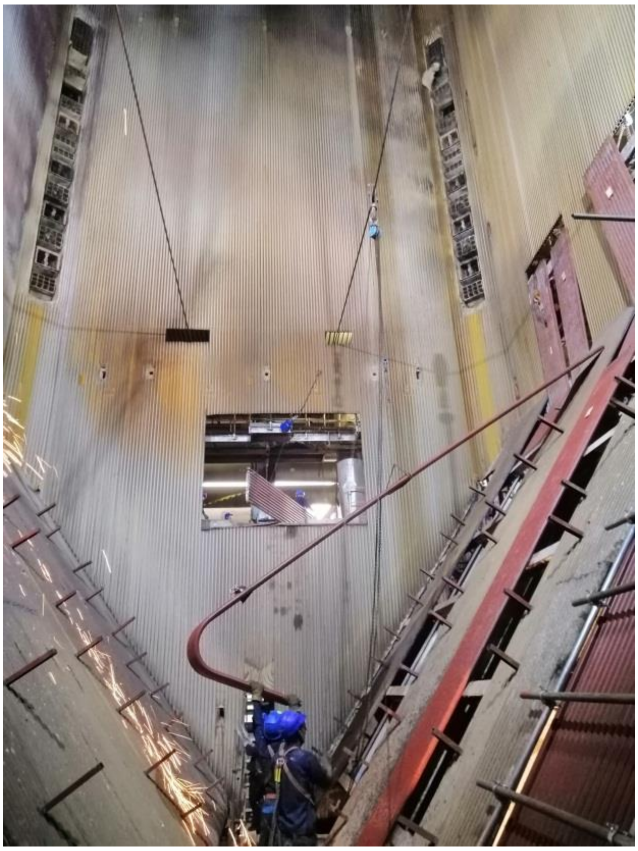


Figure 1.1: Inside structure of the boiler

For the functioning of the boiler several systems are maintaining.

1.3. Basic systems of the boiler

1.3.1. Feed water and water circulating system

Feed water is treated demineralized water and pumps to the boiler through economizer after a preheating process. After entering feed water is directed to the drum from its bottom. Water walls are used to distribute of the feed water throughout the boiler. A natural circulation process is happening in between drum and water wall through down comer pipes.

1.3.2. Drum

Saturated water and steam are reserved at the drum to maintain subcritical parameters in the thermodynamic cycle. Saturated steam outlet pipe nozzle, vent valve nozzle, and auxiliary steam nozzle are fitted and welded at the top of drum shell. Steam water mixture inlet pipe nozzle is fitted and welded at both sides. Large diameter down comer nozzle is fitted and welded at the bottom of the body, and emergency drain nozzle head is fitted with manhole, safety valve nozzle, dosing nozzle, continuous blow down piping nozzle, two pairs of local water gauge nozzles, three pairs of single balanced vessel nozzles, and a pair of electrical contacts water level indicator nozzles.

1.3.3. Superheater

The main steam flows from drum to final superheater through superheater panels. The superheater consists of seven main components. These are final superheater, rear plate superheater, isolating platen, vertical low temperature superheater, horizontal low temperature superheater, rear pass wall enclosure and ceiling superheater.

1.3.4. Reheater

The reheater consists of three main components. These are final reheater, reheater front platen, wall radiant reheater. The steam apply a Work on high pressure turbine, and then flows back into the reheater system in the boiler via cold reheat pipe. Then steam flows to low pressure turbine through the reheater panels.

1.3.5. Attemperator

There are two attemperators used to reduce steam temperature of main steam and reheated steam. The superheater attemperator is arranged for two stages to control the superheated steam temperature. The first stage is located in the connection pipeline between vertical low temperature superheater outlet header and isolating platen inlet header. The second stage is located in connection pipeline between platen superheater outlet header and final superheater inlet header. The reheater attemperator is arranged for one stage to control the reheated steam temperature. It is installed in reheater inlet pipe close to front wall radiant reheater inlet header.

1.4. Soot blowing operation

Ash is formed as a byproduct of the power generation by coal burning. Ash is scaling and fouling in boiler tubes due to various reasons. The main downfall of the scaling and fouling is heat loses occur in the furnace zone, convectional zone and back pass zone. The deposits can become unmanageable in magnitude and require an expensive outage for removal. The deposits reduce the heat transfer rate in the water wall region; resulting in reduced performance; flow obstruction; accelerated corrosion; increased mechanical loadings and increased flue gas temperature leaving the furnace.

Therefore, both retractable and rotary soot blowers are used to clean heating surfaces of the entire boiler area. Superheated steam with pressure around 1.5 MPa is used as the main energy source for soot blowing. Auxiliary steam can also be used for any uncertainties. Specific soot blowers which are mentioned in table 1.1 are usually utilized in each level of the boiler house.

Table 1.1: Soot blowers in LVPP

<table>
<tr><th>Component</th><th>Type</th><th>Quantity</th><th>Steam Consumption rate of each soot blower</th></tr>
<tr><td>Furnace soot blowers</td><td>Rotary wall soot blower</td><td>60</td><td>0.056 MT/h</td></tr>
<tr><td>Convectional pass soot blower</td><td>Long retractable soot blower</td><td>10</td><td rowspan="2">0.224 MT/h</td></tr>
<tr><td>Back pass soot blowers</td><td>Long retractable soot blower</td><td>20</td></tr>
</table>

There are 90 sets of steam soot blowers set up at furnace, horizontal and vertical gas flue path of the boiler based on the design requirements. Totally 60 sets of furnace soot blowers with model IR-3Z are set up at furnace zone. Remaining 30 sets of long expansion soot blowers with model IK-530 are set up at convection zone and back pass zone. Soot blowing is carried out by means of programmable control as in the figure 1.1.

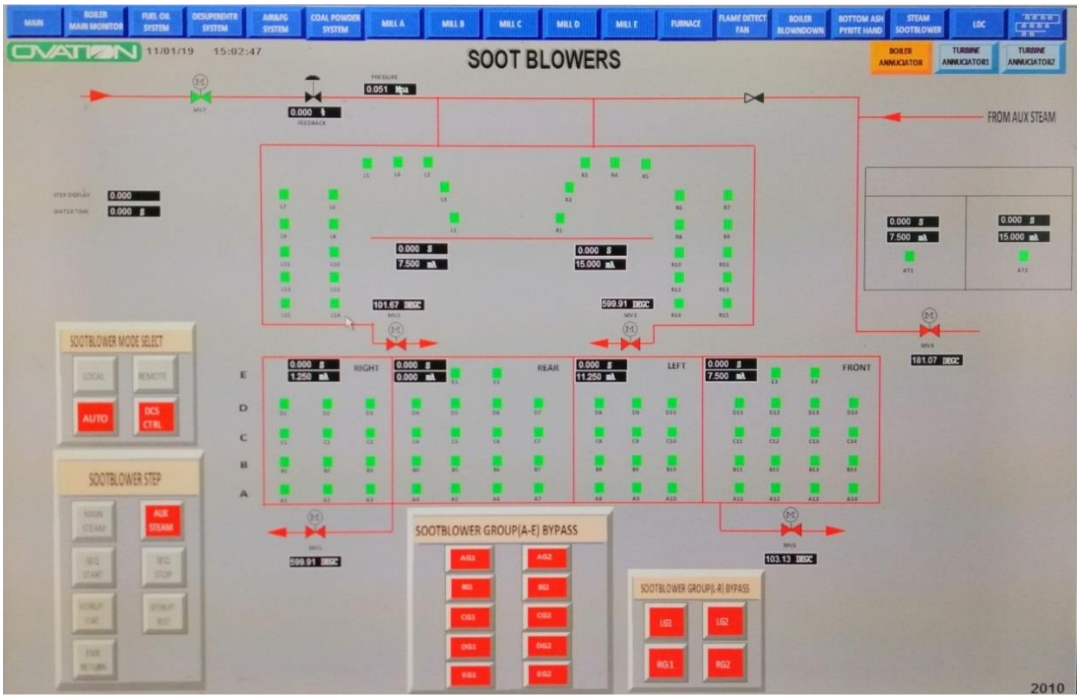


Figure 1.2: Programmable control window of soot blowing in Unit No.3

1.5. Operation mode of the boiler

There are several methods are available to run the boiler and turbine in Distributed Control System (DCS). Turbine follow and Boiler follow are the basic two methods available for operating purpose of the plant.

Coordinate control boiler follow method is used in normal operation at LVPP. In this mode coal flow rate in auto mode and turbine load (MW) can be fixed as required. Thus MW is varied according to main steam pressure. Coal flow rate can be changed any uncertainties of main steam pressure. MW value can be varied if coal flow rate is put into the manual mode.

1.6. Research Problem

There are number of parameters such as flue gas temperature, superheated steam temperature, MW generated and etc. to be considered while soot blowing in the boiler. Initially the research is focused on identifying the parameters that are affecting to the soot blowing and how these parameters could be affected to the boiler performance.

The soot blowing is carried out by means of a programmable control which is mentioned in figure 1.2. Main power plant Contractor has proposed soot blowing operation procedure schedule. According to the schedule, normal operation frequency of boiler soot blowing is in day shift of Monday, Wednesday and Friday. Air preheater (APH) soot blowing should be done both before and after boiler soot blowing. In addition, uncertain soot blowing can be carried out according to the situations on each part of gas temperature and cleanness of heating surface. Air preheater soot blowing shall be carried out continuously with auxiliary steam when oil guns are running at the time of boiler startup or boiler shutdown. In addition to that soot blowing can be carried out in any special cases. Operation engineer should monitor required parameters while soot blowing is in progress.

Soot blowers are operated from furnace area to back pass area at the boiler house. This will clean the entire heat transfer surface in the boiler to a certain extent. It was observed that following the predetermined soot blowing schedule will cause problem like abnormal flue temperature rise. Therefore it was required to schedule additional soot blowing outside the predetermined schedule. In the other hand there were some soot blowing operation conducted without significant amount of soot fouling. Therefore preparation of an optimum soot blowing schedule based on the performance of the boiler will reduce the aforementioned additional cost incurred soot blowing process.

A research problem was raised to find whether current soot blowing procedure is in an optimum stage or not and to find the parameters that will be optimized. Therefore, by this research standard operation schedule will be developed for optimum soot blowing. Further expectation is to find the rate of influence for the boiler performance and also the energy and cost saving to the power plant with this optimized schedule.

1.7. Aim and objectives

1. Identifying the parameters variation with the effect of the current soot blowing operation.
2. Estimation of the cost variation for different soot blowing frequency of operation.
3. Introducing a mathematical model to define input average fuel consumption and boiler performance for different soot blowing frequencies.
4. Estimation of effective soot blowing cost for different frequencies.
5. To figure out the cost effective optimum soot blowing frequency for Lakvijaya Power Plant.

CHAPTER 2. REVIEW OF LITERATURE

2.1. Coal - fired boiler

Pulverized coal-fired boiler technology is a major contributor to meeting worldwide electrical power generation requirements with large amount of capacity in operation today [1]. General structure of coal-fired drum type boiler is in figure 2.1.

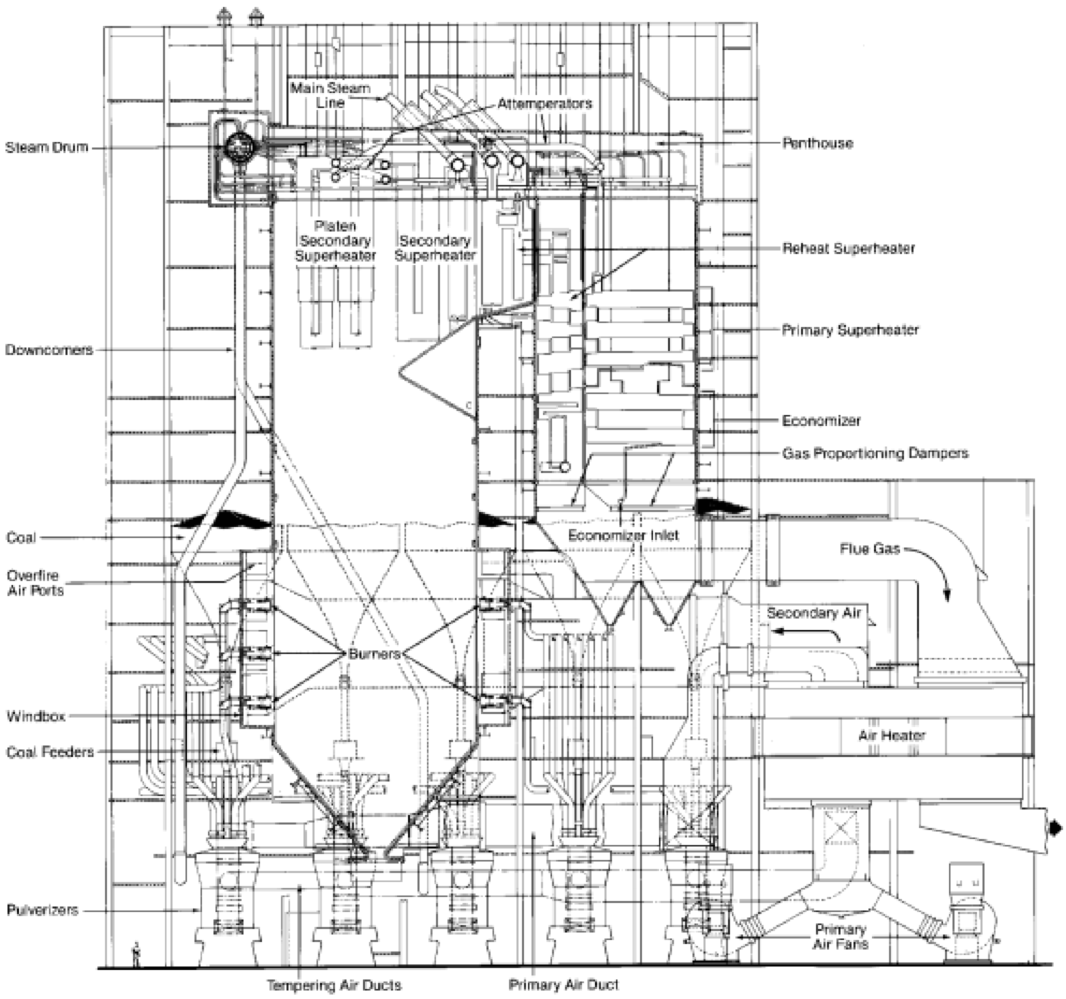


Figure 2.1: Basic structure of coal-fired drum boiler

Source: [1]

2.2. General introduction to soot blowing operation

Fly ash, also known as pulverized coal ash, is a coal combustion product that is composed of the particles that are driven out of coal-fired boilers together with the flue gas. This product is deposited in the furnace water walls, super heater panels, re-heater panels, convection pass, back pass and economizer area in the boiler [2]. Deposited ash causes to reduce the performance of the boiler. Therefore, different types of soot blowers are used to clean heating surfaces of the entire furnace area to maintain maximum thermal efficiency of the boiler.

2.3. Types of soot blowers

Long Retractable Soot Blower (LRSB) and Rotary Soot Blower (RSB) are used as basic types of soot blowers to clean the ash deposition or soot formation on heat exchanging surfaces of the tubes in coal-fired boiler [3].The basic principle of LRSB is to keep cleaning the multi surface tube banks by high impact of air, steam or water through the nozzle attached in LRSB. Several soot blowers are usually found on convection pass and back pass of the boiler. Deposited ash in super heater and re-heater platen tubes as shown in figure 2.2, can be removed by LRSB.

Figure 2.2: Super heater tubes

Source: [3]

RSB are usually found in the furnace area of the boiler that can be removed ash deposited in the furnace wall. Figure 2.3 and figure 2.4 shows LRSB and RSB respectively.

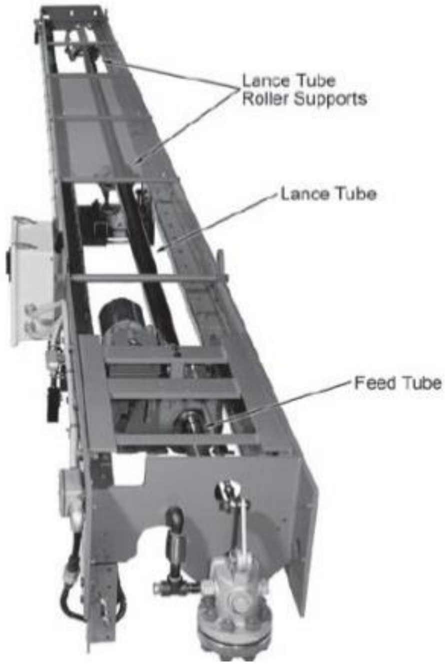


Figure 2.3: LRSB

Source: [2]

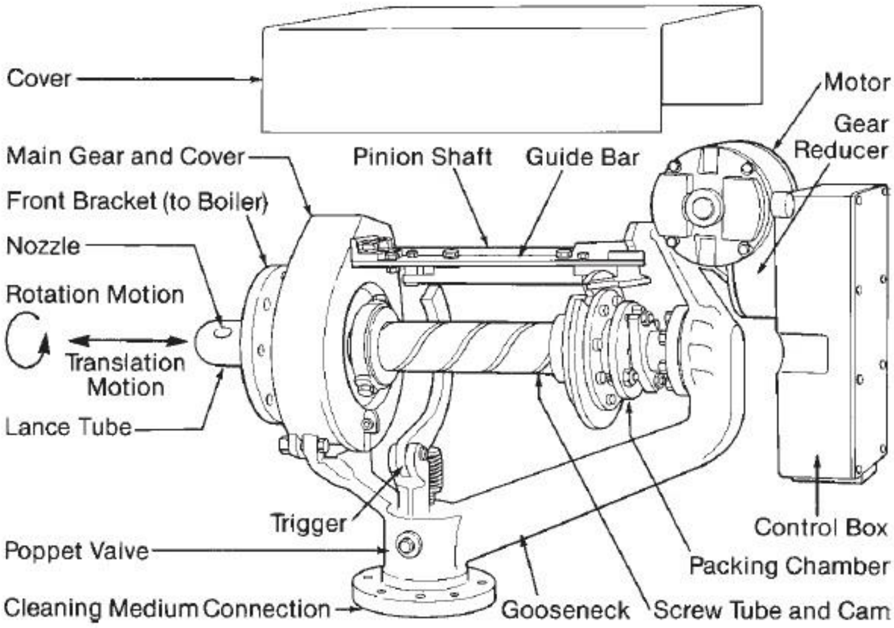


Figure 2.4: RSB

Source: [2]

2.4. Importance of soot blowing

As coal is the main energy source in the boiler which is used in powder form, lots of soot is deposited everywhere in the boiler. This will directly impact to reduce the heat transfer to the water through the tubes. Therefore frequently soot blowing operation should be carried out in order to keep the maximum efficiency of the boiler. If soot blowing frequency is insufficient, transferring heat from flue gas to steam is impeded and this results a decrease in boiler efficiency. Larger soot deposits can also restrict flue gas draft, requiring additional fan power and further reducing efficiency. On the other hand, too frequent soot blowing causes heating surface erosion and unit outages, high steam and metal temperatures, as well as increased spray flows that will reduce efficiency of most units [4].

In most existing plants, frequency of soot blowing is based on the cycle time or the instruction of the boiler operator. Often soot blowing was done once a day or once a shift basis, regardless of actual plant parameters. This typically results an over cleaning. Excessive use of steam or air is an economic penalty for this type of operations [5]. Systematic soot blowing procedure will help to improve boiler efficiency; reduce steam consumption; reduce tube erosion; reduce clinker formation; increase the range of burnable coal; reduce emissions; provide optimization based on variable goals and etc.

Therefore it is required to maintain standard soot blowing operation procedure to achieve aforementioned advantages.

2.5. Soot blowing optimization methods

2.5.1. Types of soot blowing methods for soot blowing optimization

Most of the soot blowing optimizing programs were developed by analyzing the boiler performance. Numerical method and analytical methods are the two major methods used to optimize the soot blowing operation as an energy efficient solution for the coal power plant. Considerable number of industry researches have been done regarding the control and optimize soot blowing in coal-fired boilers by using numerical and analytical methods.

2.5.1. Numerical method

2.5.1.1. Computational Fluid Dynamics (CFD) techniques

A comprehensive slagging and fouling prediction tool has been developed for coal fired boilers at Wisconsin Power in Columbia. The integration of CFD simulations with ash behavior models enables AshPro^{SM} to provide a qualitative and quantitative description of the fireside slag formation and deposition processes within the coal fired boiler. As a result, the prediction tool can be used to determine the deposit thickness, chemical composition, physical properties and heat transfer properties in a specific region of the furnace wall and convective pass. This tool can be used to assess the impact of fuel quantity, ash properties, fouling, slagging and etc. in the operation of coal-fired power plants for design and operational purpose [6]. Figure 2.5 shows that the impact of soot blowing frequency on furnace heat flux only for the furnace area.

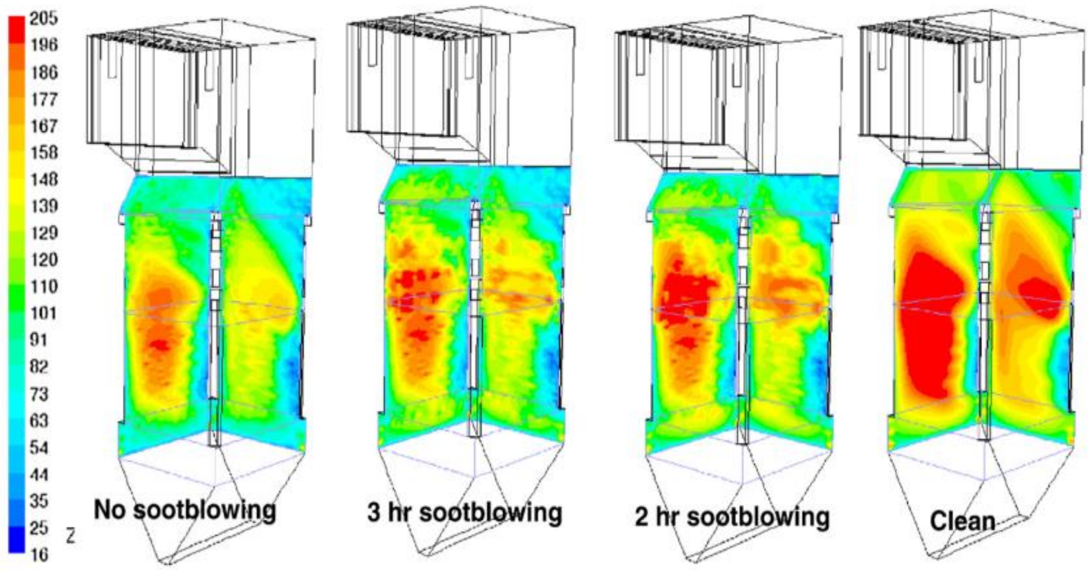


Figure 2.5: Impact of soot blowing frequency on furnace heat flux

Source: [6]

This CFD model does not provide detailed information about ash particle spreading in the convection pass of the boiler. Figure 2.6 shows the mechanism of soot deposition in convective pass pendants.

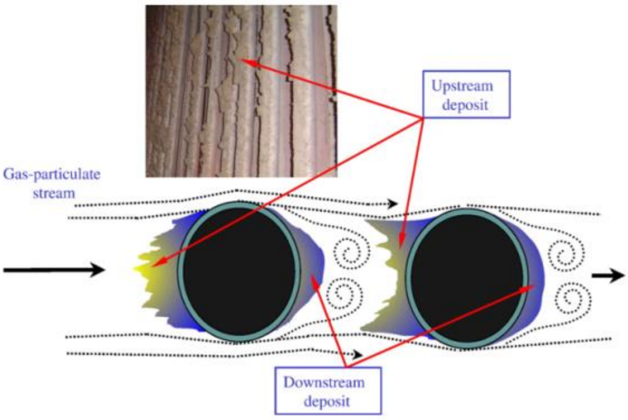


Figure 2.6: Ash deposit on tubes in convection pass

Source: [6]

Optimization of boiler parameter that affects for the soot blowing operation has been studied [7] by using CFD. Figure 2.7 indicates the behavior of the boiler efficiency with the soot blowing operation. Soot blowing happens when steam from outlet pressure is about 40 bar. The dotted line indicates how variables relate to soot blowing sequence interval. All variables have been studied to find reason between soot blowing operation and how variables behave accordingly. Efficiency has increased slightly as soot blowing operation takes places when examine the figure 2.7. At 40 bar steam pressure, most of boiler efficiency points are increasing in time.

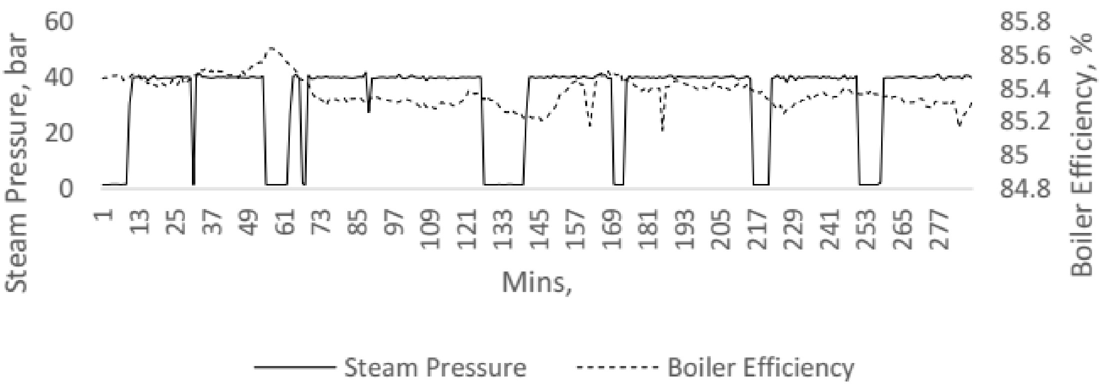


Figure 2.7: Soot blowing operation against boiler efficiency

Source [7]

Then Particle Swarm Optimization (PSO) is used as an optimization tool to optimize data obtained from plant, this provides a better function value with minimum error. The parameter model such as mean outlet flue gas temperature, total secondary air flow from the PSO model has been simulated back in CFD to ensure the parameter obtained was optimized in real time boiler condition for the best soot blowing model.

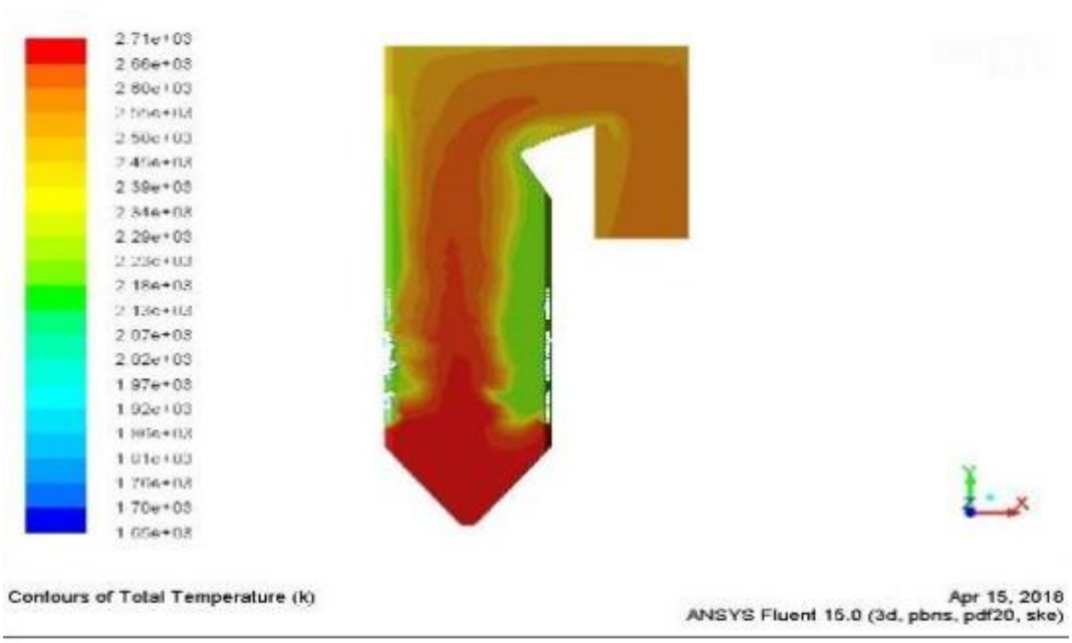


Figure 2.8: Contours of total temperature

Source: [7]

The boiler is assumed as a clean boiler when soot blowing happen [8]. When the fireball is formed and flue gas is produced, soot accumulation will take place in boiler. In Figure 2.8, the green shady green area is simulated to be area which has low temperature at 2130K region compared to region in the middle of the boiler which simulates temperature reading around 2700K. Other related parameters such as heat flux, mass fraction of soot, mass fraction of oxygen have been determined using CFD analysis. Finally this research helps to reduce unnecessary soot blowing operations in the power plant. Another research has been described the optimization of soot blower operation under the operating condition as mention in the table 2.1 in India [9].

Table 2.1: Boiler operating condition

Operating Parameters	**Value**
Mass flow of steam	2 TPH
Working pressure	11 kg/cm^2
Working temperature	265 °C
Drain flow	3 to 4 TPH
Viscosity of steam	0.6x10e-4 (Nm/s)

Source: [9]

An emphasis has been given to increase heat transfer rate, maximum thermal efficiency to save the quantity of steam & thus it is beneficial in terms of operational condition for the present work. CFD code FLUENT 14.0 is applied for the analysis purpose by model of the furnace block as in figure 2.9.

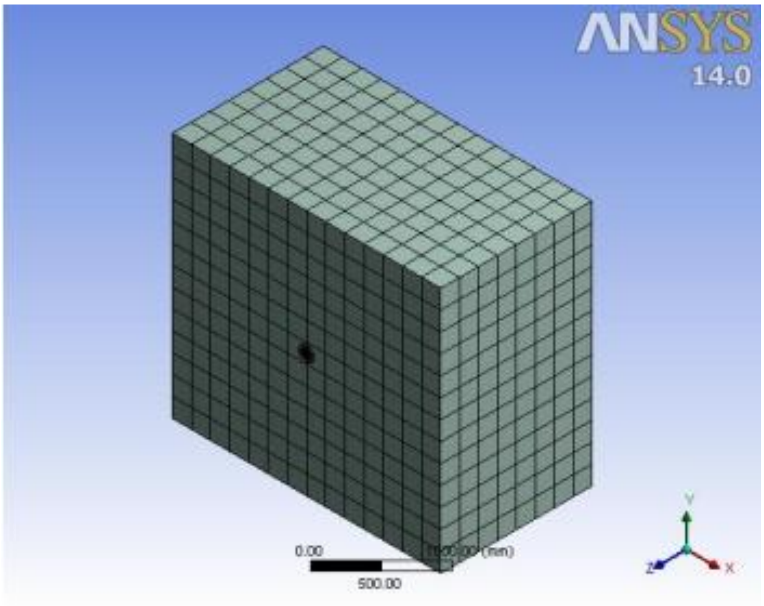


Figure 2.9: Furnace geometry in 3D in ANSYS

Source: [9]

Calculations have been carried out manually to validate the results comes from CFD calculation and nearly provide an approximate result.

As the geometry of furnace has been considered as a 3D box instead of actual furnace dimensions (figure 2.10) results of this study can be found with some deviations [9].

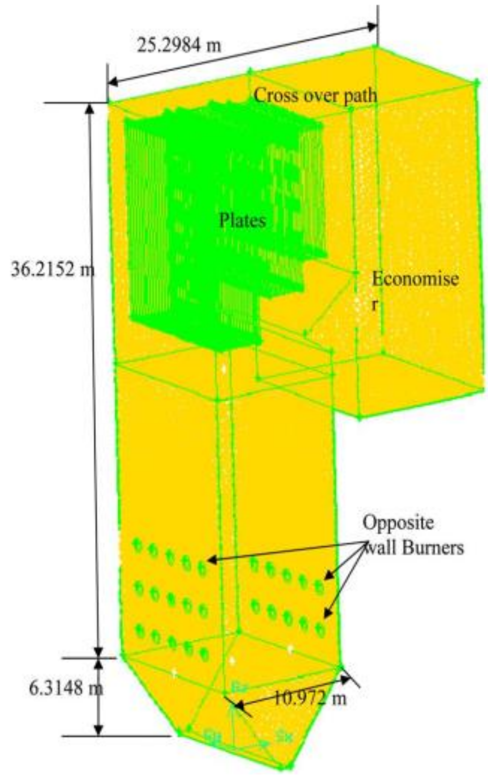


Figure 2.10: Furnace dimensions

Source: [9]

2.5.2. Analytical method

Analytical method is the most widely used method for soot blowing optimization based on the boiler efficiency. A successful boiler cleaning optimization program has been implemented to Xcel Energy’s Allen S. King station unit 1 at Las Vegas, USA. This unit is designed to supply 574 MW energy to the grid. Prior to the installation of optimized cleaning system, unit 1 was operated its soot blowing manually without monitoring the performance of the boiler. Power clean optimization system has been introduced for this unit to optimize the furnace performance [10]. Structure of boiler in Xcel Energy Allen King Unit 1 as in figure 2.11.

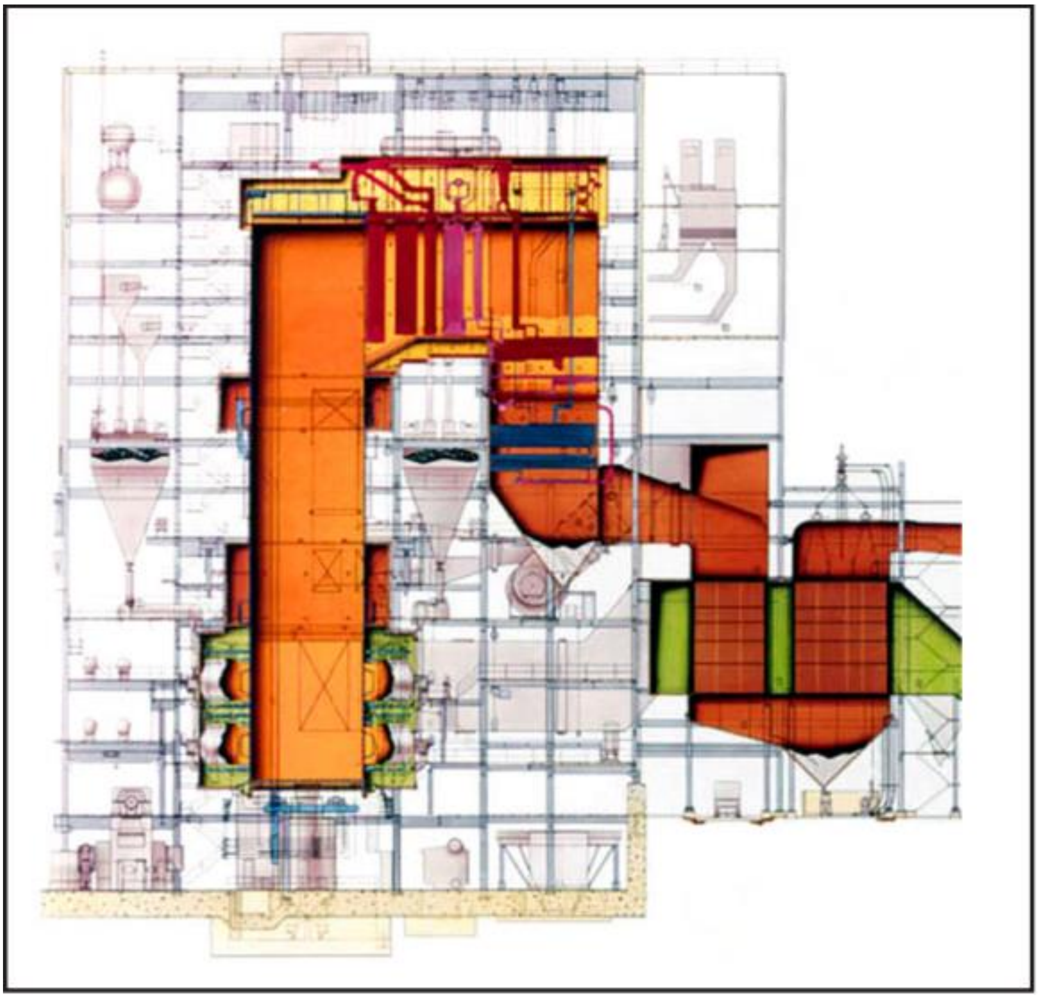


Figure 2.11: Excel energy Allen King Unit 1

Source: [10]

There was a set of sequence that was predetermined based on past soot blowing experience and recommendation from their industry expert. This sequence ran through the entire convection pass hitting all areas, whether the area was fouling or not. The soot blowing sequence lasted approximately 4 hours, which would alternate between sections throughout the convection pass. Once the sequence had stopped, the operators would restart the program. This cleaning regimen resulted in accelerated erosion and frequent boiler tube failures over a number of years.

Identified issues due to this current soot blowing operation are water wall quench cracking; one large sequence was used to clean the entire convection pass and lack of proper soot blowing practices resulted in less than optimal performance of the Allen King Unit 1.

Power clean system has introduced in order to rectify above issues and improve the furnace performance. The power clean system receives a feed of live data from the DCS which is used to calculate the heat transfer, boiler efficiency and heat rate. Then it is used to determine frequency and location of soot blowing to be initiated to optimize boiler performance.

After implementation of the new soot blowing techniques, it can be observed that the average reheat spray flow has reduced as shown in the figure 2.12.

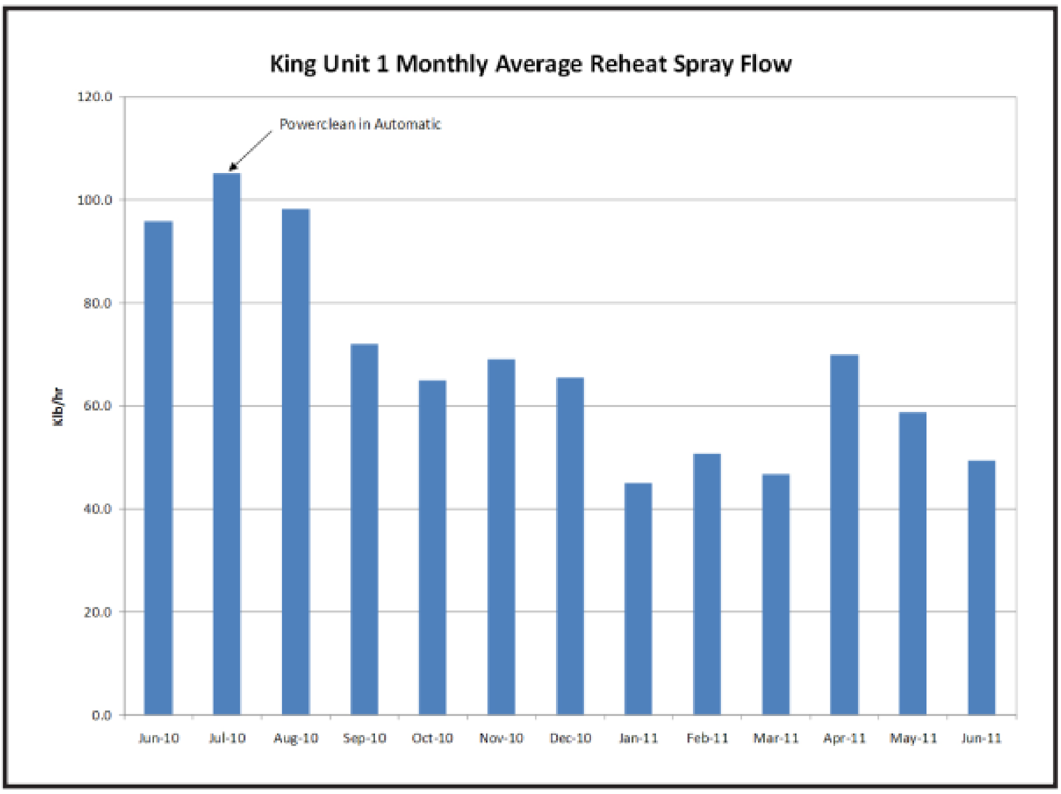


Figure 2.12: Monthly average reheat spray flow

Source: [10]

Soot blowing steam consumption has reduced as shown in the figure 2.13.

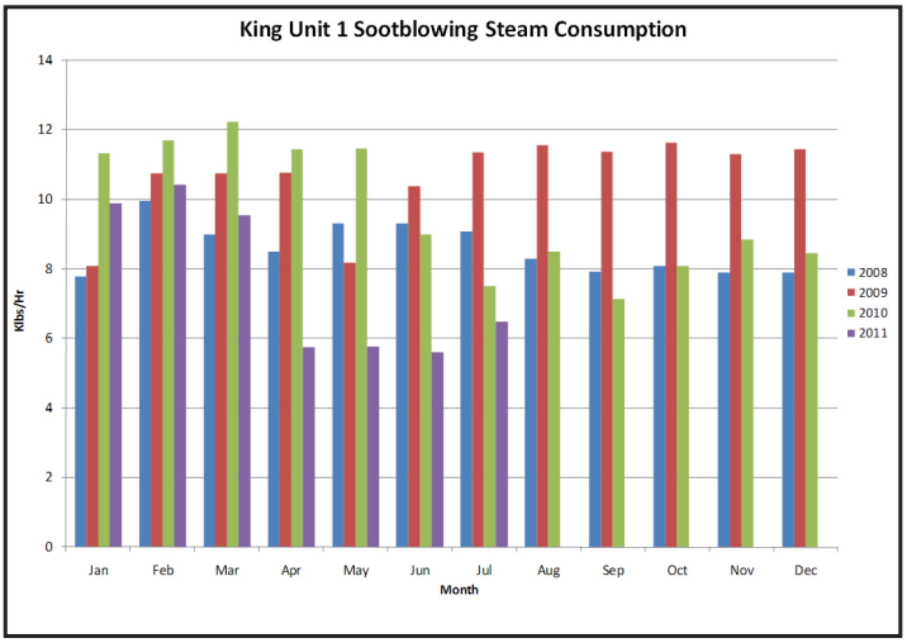


Figure 2.13: Soot blowing steam consumption

Source: [10]

Further this system has shown much less fuel is being consumed to maintain load demand as shown in the figure 2.14. The valve has increased from 1.97 MW/MT to 2 MW/MT.

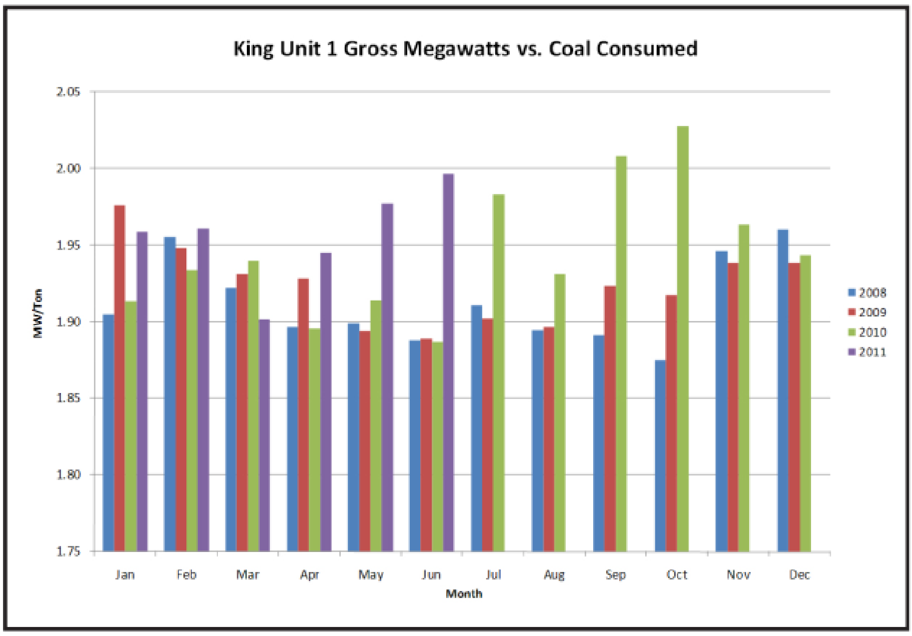


Figure 2.14: Coal consumed vs MW generated

Source: [10]

Finally this optimized system has shown best performance of the boiler with lower fuel consumption and steam usage. Based on the reduction in soot blowing steam use, King Unit 1 has realized a payback for the Power-clean system in fewer than 6 months.

2.5.2.1. Performance based analysis

Existing soot blowing procedure has been changed as per the boiler efficiency for the thermal power station-1 for NLC India Ltd. A new schedule has been introduced [5] and nearly 5% to 10% efficiency improvement was obtained. In this study a model has been developed to calculate boiler efficiency by using indirect method. Boiler efficiency variation has been determined as per the developed model for six days as mentioned in the table 2.2 by changing the sequence of operation of soot blower.

Table 2.2: Efficiency variation for six days

Day's	Period of soot blowers	Efficiency
1st	Before	74.48
1st	After	74.97
2nd	After	74.82
3rd	After	74.77
4th	After	74.66
5th	After	74.58
6th	After	74.48

Source: [5]

This study gives new schedule of operation in order to maintain the maximum boiler efficiency. 1st row of coil shall be operated once in a day, 2nd and 3rd rows of coil shall be operated twice in a week and 4th row of coil shall be operated as per the schedule. Operating parameters were studied for 4 weeks period. Its performance was analyzed as per the new schedule and compared with the design guarantee values. Fuel saving has been monitored for four days with the new schedule as mentioned in the table 2.3.

Table 2.3: Total fuel saved

Number of days	Total fuel saved
1st day	28.376 ton/day
2nd day	14.180 ton/day
3rd day	14.180 ton/day
4th day	9.450 ton/day

Source: [5]

After introducing the new schedule of soot blowing, boiler efficiency has been increased by 0.5% and the fuel gain due to new soot blowers operation at around 17 tons /day [5].

Another study has been done to identify performance and analysis of modern soot blower by improving boiler efficiency of KTPS 500 MW thermal power plant in India [11]. Boiler efficiency has been determined by using direct and indirect methods. In this research modern soot blowers have been introduced instead of the existing soot blowers. Figure 2.15 shows the results obtained with the implementation of modern soot blower to the boiler.

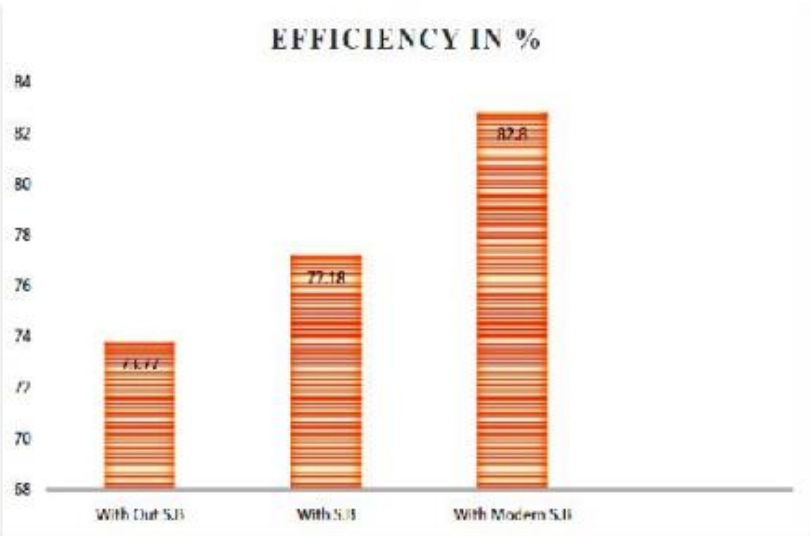


Figure 2.15: Efficiency compassion

Source: [11]

In addition to that, heat loss due to various reasons has been determined for each case as mention in the table 2.4.

Table 2.4: All the losses with various types of soot blowers

Type	Loss 1	Loss 2	Loss 3	Loss 4	Loss 5	Loss 6	Loss 7	Loss 8
Without soot blower	11.5	4.85	1.79	0.58	2.49	0.53	0.47	4.14
With soot blower	7.61	4.56	1.69	0.33	2.49	0.49	0.47	4.14
Modern soot blower	4.2	4.34	1.67	0.18	2.49	0.43	0.47	4.14

Source: [11]

By using the modern soot blower the heat loss due to dry flue gas has been reduced by 4.20%. By means of reducing the heat loss due to dry flue gas, the efficiency of the boiler has been increased up to 82.8% and more over the usage of these modern soot blowers, it reduce the number of soot blowers used in boiler [11].

2.6. Boiler efficiency calculation

Boiler efficiency calculation helps to find out how far the boiler efficiency drifts away from the best efficiency. Any observed abnormal deviations could therefore be investigated to determine the problem area for necessary corrective action. Hence it is necessary to find out the current level of efficiency for performance evaluation, which is a pre requisite for energy conservation action in a power plant.

2.6.1. Reference standard

2.6.1.1. British standards, BS845: 1987

The British Standard BS 845: 1987 describes the method and conditions under which a boiler should be tested to determine its efficiency. For the testing to be done, the boiler should be operated under steady full load condition for a period of one hour after which reading would be taken during the next hour of steady operation to enable the efficiency to be calculated.

The efficiency is quoted as a percentage useful heat available compare to the energy available in the fuel. In this case both direct and indirect methods are applicable to deals according to the complexity of the plant.

2.6.1.2. IS 8753: Indian Standard for Boiler Efficiency Testing

It is also similar to BS845 that are designed for spot measurement of boiler efficiency. Direct and Indirect methods are used to determine boiler efficiency as same as the BS845.

2.6.1.3. ASME Standard: PTC-4 1998

This standard was developed under the procedure accredited as meeting the criteria for American National Standards. In this case input and output methods are used as direct methods and heat loss method is used as an indirect method. Invariably as a loss in the efficiency, blow down has not been considered to determination process in all these standards.

Different types of boiler structures have been considered to define the performance. Figure 2.16 shows the typical structure of coal fired steam boiler with trisection APH.

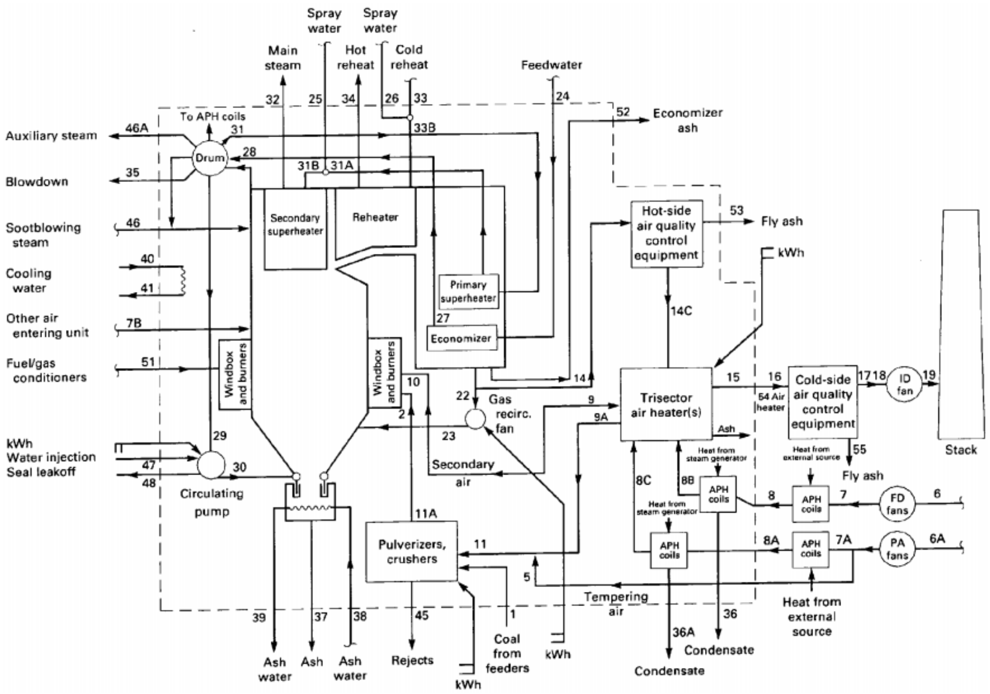


Figure 2.16: Typical structure of coal fired steam boiler with trisection air heater

2.6.2. Direct method

To find out boiler efficiency the direct method is adopted because it is an easier method that uses simple calculations and the data readily given by the instruments. Quantity of steam generated, steam pressure, Steam temperature, feed water temperature and enthalpy of feed water can be used as heat output data. Quantity of coal consumed and Gross calorific Value (GCV) of coal can be considered as heat input data [11]. Boiler efficiency is given by the equation 2.1.

$$\eta = \frac{Q\ (H - h)}{q\ \times \text{GCV of coal}} \times 100 \qquad (2.1)$$

Where,

η = Efficiency of the boiler (%)

Q = Quantity of steam generated per hour (kg/hr)

H = Enthalpy of steam (kCal/kg)

h = Enthalpy of feed water (kCal/kg)

q = quantity of coal used per hour (kg/hr)

GCV = Gross calorific value of coal (kCal/kg)

Direct method facilitates some benefits such as quick evaluation of boiler efficiency, requirement of fewer parameters for computation and requirement of fewer instruments for monitoring.

2.6.3. Indirect method

The efficiency can be measured easily by measuring almost all of the heat losses associated with the boiler. The efficiency can be obtained by subtracting the heat loss percentages from 100. An important advantage of this method is that the errors in measurement do not make significant change in efficiency [6]. This method is also named as energy balance method in ASMI PTC-4 standard. Fuel properties, combustion air properties, atmospheric parameters, residue parameters and flue gas parameters are used to determine all losses related to the boiler activities.

2.6.3.1. Data analysis of fuel

Higher Heating Value of Fuel (HHVF) is referring on a constant pressure basis and determining from a bomb calorimeter. Fuel properties shown in table 2.5 need to be obtained for the analysis.

Table 2.5: Analysis data of fuel

Elements in fuel	Short term	Unit	Description
C	MpCF	mass%	Mass percent of C in fuel
H	MpH2F	mass%	Mass percent of H_2 in fuel
N	MpN2F	mass%	Mass percent of N_2 in fuel
O	MpO2F	mass%	Mass percent of O_2 in fuel
S	MpSF	mass%	Mass percent of S_2 in fuel
Moisture	MpWF	mass%	Mass percent of water in fuel
Fixed carbon	MpFc	mass%	Mass percent of fixed carbon
Volatile matter	MpVm	mass%	Mass percent of Volatile matter
Ash	MpAsF	mass%	Mass percent of ash in fuel
Lower heating value	LHVF	kJ/kg	Lower heating value of fuel
Higher healing value	HHVF	kJ/kg	Higher heating value of fuel

2.6.3.2. Atmospheric parameters

Atmospheric conditions are mentioned in the table 2.6.

Table 2.6: Atmosphere parameters

Parameter	Short term	Unit	Remarks
Barometric pressure	Pa	kPa	Pressure in atmosphere
Partial pressure	Pp	kPa	To be measured
Dry-bulb temperature	Tdb	°C	To be measured
Dry-bulb temperature	TdbF	F	See Eq. 2.2
Wet-bulb temperature	Twb	C	Temp. of air
Relative humidity	Rhm	%	To be measured
Saturation pressure of water vapor at Tdb	PsWvTdb	kPa	See Eq. 2.3
Partial pressure of water vapor in air	PpWvA	kPa	See Eq. 2.4
Mass fraction of Moisture in dry air	MFrWDA	kg/kg DA	See Eq. 2.5
Mass fraction of Moisture in wet air	MFrWA	kg/kg WA	See Eq. 2.6

Temperature in dry bulb is obtained by equation 2.2.

$$TdbF = (1.8 \times Tdb) + 32 \qquad (2.2)$$

Saturation pressure of water vapor at Tdb is obtained by equation 2.3

$$PsWvTdb = C1 + C2Tdb^2 + C3Tdb^3 + C4Tdb^4 + C5Tdb^5 + C6Tdb^6 \qquad (2.3)$$

Where,

C1= 0.019257

C2=1.289016E-3

C3=1.211220E-5

C4=4.534007E-7

C5=6.841880E-11

C6=2.197092E-11

The curve fit is valid for temperatures from 32 °F to 140 °F.

The moisture in air is determined from measured inlet air wet bulb and dry bulb temperature or dry bulb temperature and relative humidity in conjunction with psychometric chart, calculated from vapor pressure as determined from Carrie's equation 2.4 , 2.5 and 2.6.

$$PpWvA = 0.01 \times Rhm \times PsWvbTdb \qquad (2.4)$$

$$MFrWDA = 0.622 \frac{PpWvA}{(Pa - PpWvA)} \qquad (2.5)$$

$$MFrWA = \frac{MFrWDA}{(1 + MFrWDA)} \qquad (2.6)$$

2.6.3.3. Air and flue gas parameters

Flue gas quantity is calculated stoichiomerically from the coal analysis and excess air. Computational methods are not valid if significant quantities of unburned hydrocarbons are present in the flue gas. The total gaseous products excluding moisture are referred to as dry flue gas and are used in the energy balance efficiency calculations. Table 2.7 indicates required air and flue gas parameters for efficiency calculation.

Table 2.7: Air and flue gas parameters

Air and flue gas parameter	Short term	Unit	Remarks
Primary air temp. at APH inlet	TAEnP	°C	Inlet temperature at AH
Secondary air temp. at APH inlet	TAEnS	°C	Outlet temperature at AH
Primary air flow	MFW1	kg/h	Primary air flow
Secondary air flow	MFW2	kg/h	Secondary air flow
Primary air rate	Xpa		MFW1/(MFW1+MFW2)
Secondary air rate	Xsa		MFW2/(MFW1+MFW2)
Air temperature entering the boiler	TMnAEn	°C	(TAEnP*Xpa)+ (TAEnS*Xsa)
Flue gas temp	TFg	°C	Flue gas temperature
O2 content	VpO2e	Vol% dry base	O2 content in flue gas at AH inlet
O2 content	VpO2	Vol% dry base	O2 content in flue gas at AH outlet

2.6.3.4. Residue properties

Residue is the ash and unburned coal removed from the boiler. Residue is analogous to refuse when used to refer to the solid waste material removed from a coal fired steam boiler.

Table 2.8: Residue properties

Residue properties	Short term	Unit	Remarks
Unburned total carbon in fly ash	MpToCRsfa	mass%	Chemical Analysis Data
Unburned total Carbon in bottom ash	MpToCRsba	mass%	Chemical Analysis Data
Mass fraction of fly ash	MpRsfa	mass%	To be measured
Mass fraction of bottom ash	MpRsba	mass%	To be measured
Unburned carbon in residue	MpToCRs	mass%	See Eq. 2.7
Total mass of residue per mass fuel	MFrRs	kg/kg fuel	See Eq. 2.9
Unburned carbon in fuel	MpUbC	mass%	See Eq. 2.10
Carbon burned in fuel	MpCb	mass%	See Eq. 2.11
Carbon burnout	MpCbo	%	See Eq. 2.12
Mass of rate of fly ash	MqRsf	kg/kJ	See Eq. 2.13
Mass of residue of bottom ash	MqRsb	kg/kJ	See Eq. 2.14

When residue is collected at more than one location the weighted of total carbon and total carbon dioxide in residue is calculated from equation 2.7 and 2.8

$$MpToCRs = \frac{\sum Mp\,Rsz(fa, ba) \times MpToCRsz(fa, ba)}{100} \tag{2.7}$$

$$MpToCO2Rs = \frac{\sum Mp\,Rsz(fa, ba) \times MpToCO2Rsz(fa, ba)}{100} \tag{2.8}$$

Where,

$MpRs(fa, ba)$ = Mass fraction of fly ash and bottom ash

$MpToCRsz(ba)$ = Unburned total carbon in fly bottom ash

$MpToCO2Rsz(ba)$ = Unburned total carbon dioxide in bottom ash

Mass of residue is given by equation 2.9.

$$MFrRs = \frac{MpAsF + 100MFrSsb}{(100 - MpToCRs)} \tag{2.9}$$

Where,

$MpAsF =$ Ash in fuel, percentage of mass

$MFrSsb =$Mass fraction of spent sorbent per mass of fuel

$MpToCRs =$Uunburned total carbon in the residue, percentage of mass

The unburned carbon in the residue as shown in the equation 2.10 is used to calculate the percent of the carbon in the fuel that is unburned.

$$MpUbC = MpToCRs \times MFrRs \tag{2.10}$$

The actual carbon burned (MpCb) which is calculated from equation 2.11 is used in the stoichiometric combustions in lieu of carbon in fuel (MpCF).

$$MpCb = MpCF \times MpUbc \tag{2.11}$$

Carbon burnout is the carbon burned divided by the carbon available and expressed as a percentage in equation 2.12.

$$MpCbo = \frac{MpCb}{MpCF} \times 100 \tag{2.12}$$

Mass flow rate of fly ash and bottom ash is given by the equation of 2.13 and 2.14 respectively.

$$MqRsf = \frac{MqRsfa \times MFrRs}{100\, HHVF} \tag{2.13}$$

$$MqRsb = \frac{MqRsba \times MFrRs}{100\, HHVF} \tag{2.14}$$

2.6.3.5. Combustion air properties

Table 2.9: Combustion air properties

Combustion properties	Short term	Unit	Remarks
Typical value of theoretical air for fuel, ideal	MqThAf	kg/kJ	See Eq.2.15
Mass of theoretical air corrected	MFrThACr	kg/kg fuel	See Eq. 2.18
Theoretical air corrected	MqThACr	kg/kJ	See Eq.2.17
Moles of theoretical air required (corrected)	MoThACr	kmoles/kg fuel	See Eq. 2.19
Moles of dry products from fuel combustion	MoDPc	kmoles/kg fuel	See Eq.2.21
Moles of wet products from fuel combustion	MoWPc	kmoles/kg fuel	See Eq. 2.22
Moles of moisture in air	MoWA	moles/moles dry air	1 .608MFrWDA
Excess air at APH inlet	XpAe	%	See Eq.2.21
Excess air at APH outlet	XpA	%	See Eq. 2.20
Moles wet gas per mass fuel at APH inlet	MoFge	kmoles/kg fuel	See Eq.2.23
Moles wet gas per mass fuel at APH outlet	MoFg	kmoles/kg fuel	See Eq. 2.23
Mass of dry air at APH inlet	MqDAe	kg/kJ	See Eq. 2.24
Mass of dry air at APH outlet	MqDA	kg/kJ	See Eq. 2.24
Mass of wet air at APH inlet	MqAe	kg/kJ	See Eq. 2.25
Mass of wet air at APH outlet	MqA	kg/kJ	See Eq. 2.25

Theoretical air is defined as the ideal minimum air required for the complete combustion of the fuel. Meaning of that carbon, hydrogen and sulfur is completely become CO_2, H_2O and SO_2 respectively. In the actual combustion process, small amount of CO and nitrous oxide are formed and commonly measured. Also small amount of SO_3 and gaseous hydrocarbons are formed but less frequently measured and has been neglected by this code.

Typical value of theoretical air for fuel in ideal condition is given by the equation 2.15.

$$MqThAf = \frac{MFrThA}{HHVF} \tag{2.15}$$

Mass of theoretical air corrected equation is mentioned in 2.16.

$$MFrThA = 0.1151\, MpCF + 0.3430\, MpH2F + 0.0431\, MpSF \\ -0.0432\, MpO2F \tag{2.16}$$

Where, fuel constituents MpCF, MpH2F, MpSF and MpO2F are on percentage mass basis.

Corrected theoretical air is defined as the amount of air required for complete combustion of the fuel with zero excess oxygen. Moreover the theoretical products of combustion would have no CO or gaseous hydrocarbons.

$$MqThACr = \frac{MFrThACr}{HHVF} \tag{2.17}$$

$$MFrThACr = 0.1151\, MpCb + 0.3430\, MpH2F \\ +0.0431\, MpSF(1 + 0.5\, MFrSc) \tag{2.18}$$

$$MoThACr = \frac{MFrThACr}{28.963} \tag{2.19}$$

Where,

$MqThACr =$ Theoretical air (corrected)

$MoThACr =$ Moles of theoretical air required (corrected)

$MpCb =$ Carbon burned on mass percentage basis

$MFrSc =$ Sulfur capture ratio

Excess air is the actual quantity of air used, minus the theoretical air required divided by the theoretical air and expressed as a percentage in equation 2.20.

$$XpA = 100\frac{(MFrDA - MFrThACr)}{MFrThACr} \tag{2.20}$$

For the efficiency calculation excess air shall be determined at the boiler outlet. Considering the oxygen analysis in the excess air the equation is modified as 2.21.

$$XpA = 100\frac{DVpO2(MoDPc + 0.7905\ MoThACr)}{MoThACr(20.95 - DVpO2)} \tag{2.21}$$

$$MoDPc = \frac{MpCb}{1201} + (1 - MFrSc)\frac{MpSF}{3206.4} + MpN2\frac{F}{2801.3} + MoCO2Sb \tag{2.21}$$

Where,

$DVpO2 =$ Oxygen concentration in the flue gas, percent by volume, dry basis

$MoDPc =$ Moles of dry products from the combustion of fuel

$MFrSc =$ Mass fraction of sulfur capture

$MoCO2Sb =$ Moles of gas from sorbent

Oxygen analysis on wet product, where the gas samples includes moisture is expressed by the equation 2.22.

$$MoWPc = MoDPc + \frac{MpH2F}{201.6} + \frac{MpWF}{1801.5} \tag{2.22}$$

Moles of wet gas per mass of fuel fired is expressed in equation 2.23.

$$MoFg = MoWPc + MoThACr(0.7905 + MoWA + \tfrac{XpA}{100}(1 + MoWA)) \tag{2.23}$$

The quantity of dry air entering the boiler at location z is calculated from the excess air determined to be present at location z in equation 3.24.

$$MqDAz = MqThACr\ (1 + \tfrac{XpAz}{100}) \tag{3.24}$$

The quantity of wet air at any location z is expressed in equation 3.25.

$$MqAz = MqDAz(1 + MFrWA) \tag{3.25}$$

2.6.3.6. Flue gas parameters

Table 2.10: Flue gas parameters

Flue gas parameter	Short term	Units	Remarks
Wet gas from fuel	MqFgF	kg/kJ	See Eq. 2.26
Moisture from H20 in fuel	MqWF	kg/kJ	See Eq. 2.27
Moisture from the combustion of hydrogen in the fuel	MqWH2F	kg/kJ	See Eq. 2.28
Moisture in air at APH inlet	MqWAe	kg/kJ	See Eq. 2.30
Moisture in air at APH outlet	MqWA	kg/kJ	See Eq. 2.30
Total moisture in flue gas at APH inlet	MqWFge	kg/kJ	See Eq.2.31
Total moisture in flue gas at APH outlet	MqWFg	kg/kJ	See Eq. 2.31
Total wet flue gas weight at APH inlet	MqFge	kg/kJ	See Eq.2.32
Total wet flue gas weight at APH outlet	MqFg	kg/kJ	See Eq. 2.32
Dry flue gas weight at APH inlet	MqDFge	kg/kJ	See Eq. 2.33
Dry flue gas weight at APH outlet	MqDFg	kg/kJ	See Eq. 2.33

Wet gas from fuel is expressed in Equation 2.26.

$$MqFgF = \frac{(100 - MpAsF - MpUbc - MFrSc.MpSF)}{100\ HHVF} \tag{2.26}$$

Where,

$MpAsF =$ Ash in fuel, percentage of mass

$MpUbc =$ Unburned carbon, percentage of mass

$MFrSc =$ Mass fraction of sulfur capture

$MpSF =$ Sulfur in fuel

Moisture from H_2O in fuel is given by the Equation 2.27.

$$MqWF = \frac{MpWF}{100\ HHVF} \tag{2.27}$$

Where, MpWF is the water in the fuel, percentage of mass.

Moisture from the combustion of hydrogen in the fuel is expressed by the Equation 2.29.

$$MqWH2F = \frac{8.937\ MpH2F}{100\ HHVF} \tag{2.29}$$

Moisture in air is proportional to excess air and shall be calculated for each location z where excess air is determined by the Equation 2.30.

$$MqWAz = MFrWA \times MqDAz \tag{2.30}$$

Total moisture in flue gas at any location z is the sum of individual sources which is expressed in Equation 2.31.

$$MqWFgz = MqWF + MqWAz + MqWH2F \tag{2.31}$$

Total wet flue gas weight and dry flue gas weight at any location z is given by the Equation 2.32 and 2.33 respectively.

$$MqFgz = MqDAz + MqWAz + MqFgF \tag{2.32}$$

$$MqDFgz = MqFg - MqWFgz \tag{2.33}$$

2.6.4. Calculation of heat loss

2.6.4.1. Method of calculation

The calculation of losses falls into two categories in accordance with the method in which they are measured and conveniently calculated. The first category is the losses that are functions of input from fuel and can be readily expressed in terms of loss per unit of input from fuel.

The second category are losses not related to fuel input, those are more readily calculated on energy per unit of time basis, such as the loss due to surface radiation and convection. Table 2.11 indicates the second category of losses for each factor which causes for heat losses.

2.6.4.2. Heat loss in dry flue gas

Table 2.11: Dry flue gas loss

Parameter	Short term	Unit	Remarks
Enthalpy of dry air at TFg	HADg	kJ/kg	See Eq. 2.34
Air temperature entering the boiler	TMnAEnK	K	273.15+TMnAEn
Air temperature entering the boiler	TMnAEnF	F	1 .8TMnAEn+32
Enthalpy Of dry air at TMnAEn	HADa	kJ/kg	See Eq. 2.35
Enthalpy of water vapor at TFgF	HWvg	kJ/kg	See Eq. 2.35
Enthalpy of water vapor at TMnAEnF	HWva	kJ/kg	See Eq.2.35
Enthalpy of wet air at TFg	HATFg	kJ/kg	See Eq. 2.36
Enthalpy of wet air at TMnAEn	HAEn	kJ/kg	See Eq. 2.36
Mean Specific heat of wet air	MnCpA	kJ/kgK	See Eq. 2.37
Corrected flue gas temperature	TFgc	C	See Eq. 2.38
Temperature of flue gas at APH outlet	TFgF	F	1.8TFgc+32
Temperature of flue gas at APH outlet	TK	K	273.15+TFgc
Enthalpy dry flue gas	HDFg	kJ/kg	See Eq. 2.39
Dry flue gas loss	QpLDFg	%	See Eq. 2.40

Enthalpy of dry air at temperature TK of flue gas is expressed in Equation 2.34.

$$HAD = C0 + C1TK + C2TK^2 + C3TK^3 + C4TK^4 + C5TK^5 \qquad (2.34)$$

Where, C0= -0.2394034E+03, C1= +0.8274589E+00, C2=-0.1797539E-03, C3=+0.3934614E-06, C4=-0.2415873E-09, C5= +0.6069364E-13.

Enthalpy of water vapor is at temperature T is given by the Equation 2.35.

$$HWv = 0.4408T + 2.381E - 5T^2 + 9.638E - 9T^3 \qquad (2.35)$$

Enthalpy of air at temperature T is a function of mass of the mixture of dry air and water vapor in air that is expressed in Equation 2.36.

$$HAT = (1 - MFrWA) \times HAD + MFrWA \times HWv \tag{2.36}$$

When the mean specific heat is required for wet air, it is obtained in Equation 2.37

$$MnCpA = \frac{(HATFg - HAEn)}{(TFgK - TMnEnK)} \tag{2.37}$$

When there are two or more air heaters with approximately the same gas flow through each, the air and gas temperature shall be averaged and corrected for gas temperature calculation. Corrected flue gas temperature is given by the Equation 2.38.

$$TFgC = TFg + \frac{(MnCpA)}{(MnCpFg)}\left(\frac{MqFg}{MqFge} - 1\right) \times (TFg - TMnAEn) \tag{2.38}$$

Enthalpy of dry flue gas is expressed by the Equation 2.39.

$$HDFg = C0 + C1TK + C2TK^2 + C3TK^3 + C4TK^4 + C5TK^5 \tag{2.39}$$

Where, C0= -0.1231899E+03, C1= +0.4065568E+00, C2=+0.5795050E-05, C3=+0.6331121E-07, C4=-0.2924434E-10, C5= +0.2491009E-14.

Percentage of dry flue gas loss is given by the Equation 2.40.

$$QpLDFg = 100MqDFge \times HDFg \text{ (\%)} \tag{2.40}$$

2.6.4.3. Loss due to water in fuel

Table 2.12: Loss due to water in fuel

Parameters	Short term	Unit	Description
Enthalpy of water vapor at TFgF	HSt	kJ/kg	See Eq. 2.41
Reference air temperature	TradF	F	1.8Trad+32
Enthalpy of water at TradF	HWRe	kJ/kg	TradF-32
Loss due to water in fuel	QpLWF	%	See Eq.2.42

Enthalpy of water vapor at temperature TFgF is given by the Equation 2.41.

$$HSt = 0.4329TFgF + +3.958E - 5TFgF^2 + 1062.2 \tag{2.41}$$

Loss due to water in fuel is expressed in Equation 2.42.

$$QpLWF = 100MqWF(HSt - HWRe)\ (\%) \tag{2.42}$$

2.6.4.4. Loss due to water formed from the combustion of H2 in fuel

Loss due to water formed from the combustion of H_2 in fuel is expressed in Equation 2.43.

$$QpLH2F = 100MqWH2F(HSt - HWRe)\ (\%) \tag{2.43}$$

2.6.4.5. Loss due to moisture in air

Enthalpy of water vapor is given by the equation 2.44.

$$HWvRs = C0 + C1TK + C2TK^2 + C3TK^3 + C4TK^4 + C5TK^5 \tag{2.44}$$

Where, C0= -239.4034, C1= +0.8274589, C2=+0.1797539E-04, C3=+0.39346E-07, C4=-2.4E-10, C5= +6.069264E-14.

Loss due to moisture in air is expressed in Equation 2.45.

$$QpLWA = 100MFrWDA \times MqDAe \times HWvRs\ (\%) \tag{2.45}$$

Where,

$MqDAe =$ Mass of dry air corresponding to the excess air used for dry gas loss

2.6.4.6. Loss due to unburned carbon in residue

$$QpLUbC = MpUbC\frac{HHVCRs}{HHVF}\ (\%) \tag{2.46}$$

Where,

$HHVCRs$ is the heating value of carbon as it occurred in residue.

2.6.4.7. Loss due to unburned H2 in residue

$$QpLH2Rs = \frac{MrRs.MpH2Rs.HHVH2}{MrF.HHVF}\ (\%) \tag{2.47}$$

Where,

$MpH2Rs$ is the weighted average mass of unburned in residue.

$HHVH2$ = 142,120 kJ/kg.

2.6.4.8. Loss due to CO in flue gas

$$QpLCO = VpCO.MoDFg.MwCO\frac{HHVCO}{HHVF}\ (\%) \tag{2.48}$$

Where,

$DVpCO =$ Quantity of CO measured in dry basis, percentage of volume

$VpCO$ = Quantity of CO measured on wet basis. Percentage of volume

$MoDFg =$ Moles of dry gas with excess air measured

$MwCO =$ Molecular weight of CO

$HHVCO =$ Higher heating value of CO

Similar equation can be used for calculation of unburned hydrocarbon in flue gas.

2.6.4.9. Loss due to surface radiation and convection

Loss due to surface radiation and convection is determined by Equation 2.49.

$$QrLSrc = Cl\sum(Hcaz + Hraz)Afz(TmnAfz - TMnAz) \tag{2.49}$$

Where,

$$Hcaz = larger\ of\ 0.2\ (TMnAfz - TMnAz)^{1/3}\ \text{ or }\ 0.35\ VAz^{4/5}$$

$$Hraz = 0.847 + 2.367E - 3TDi + 2.94E - 6Ti^2 + 1.37E - 9TDi^3$$

$Hcaz =$ Convection heat transfer coefficient for area z.

$Hraz$ = Radiation heat transfer coefficient for area z.

$Afz =$ Flat projected surface area of the casing lagging over the insulation for location z

$TMnAfz =$ Average surface temperature of area z

$TMnAz =$ Average ambient air temperature of area z

$TDi = (TAfz - TAz)$

$VAz =$Average velocity air near surface

$Cl = 0.293$

2.6.4.10. Efficiency of the boiler

Efficiency of the boiler is given by Equation 2.50.

$$EFH = 100 - \sum QpLn \qquad (2.50)$$

Where,

$EFH =$ Efficiency of the Boiler

$\sum QpLn =$ Sum of losses

CHAPTER 3: RESEARCH METHODOLOGY

3.1. Identification of parameter variation with soot blowing

The research focuses on study and optimization of soot blowing operation for a coal power plant in Sri Lanka. LVPP was selected for the research as this is the one and only coal power plant in Sri Lanka. Related data was collected from Unit No.3 in LVPP. Initially behavior of the parameters such as flue gas temperature, superheated steam temperature, superheated steam pressure and etc. which are related for soot blowing process and for the current soot blowing operation were observed.

Presently several methods are available for boiler and turbine operation as discussed in the Chapter 1.4. The boiler which is at the Unit No.1 in LVPP was operating under the boiler follow mode by a fixed coal flow rate. Therefore, variation of turbine output power (MW) was accurately identified using soot blowing process at Unit No.1 Remaining output parameters such as flue gas temperature was studied at Unit No.3 in boiler follow mode with a deviation of coal flow rate.

3.2. Calculating the boiler efficiency

Boiler efficiency was calculated using the energy balance indirect method by the Equation 2.50 in accordance with the standard of ASMI PTC4-1998. The boiler efficiency for the current condition of Unit No.3 in LVPP was also determined. A mathematical model was developed to find the boiler efficiency in various condition.
Frist data of boiler inputs and outputs were measured and entered to relevant equations which was described in Chapter 2.6. Different type of loses were calculated prior to the calculation of boiler efficiency using the developed mathematical model. Similarly, boiler efficiency was calculated by changing the normal routine of soot blowing for considerable period of time. Different output parameters with respect to soot blowing frequencies were obtained in Unit No.3.

In addition to that chemical properties of the coal were observed and determined at chemical laboratory in LVPP.

3.3. Finding the relationship between coal flow rate and soot blowing frequency

Currently coal is imported from Indonesia and South Africa as the main energy source to the boiler. Coal was imported from South Africa was used during this research period for all units in LVPP. Always coal flow rate is measured remotely by weigh feeders before feeding into the coal mills and observations are done by operation engineer through the DCS window. Average coal flow rate was obtained at different soot blowing frequencies. A relationship was derived using both raw data and processed data. Finally a formula was defined in order to find coal flow rate for any soot blowing frequency.

3.4. Calculating the fuel cost

The annual cost for coal was obtained using the unit price of coal as in monthly performance report of LVPP. The cost of coal variation for different soot blowing frequencies was calculated throughout the year and compared with cost for normal routine of soot blowing.

3.5. Calculating the soot blowing cost

As main steam is the main energy source for soot blowing, fixed pressure level of the main steam tries to fall but additional coal burns to keep the pressure without falling in the boiler follow mode with deviation of coal flow rate in Unit No.3. The amount of additional coal burnt to get the required steam quantity for soot blowing and the amount of additional steam that was required for the soot blowing need to be calculated.

The flue gas loss and steam consumed for soot blowing were included to the total cost for soot blowing. Thus the soot blowing cost per year for different frequencies was obtained as the sum of hourly outputs of those mentioned parameters.

It is practically impossible to measure the direct steam consumed for soot blowing operation. Therefore an indirect approach was taken to measure the direct steam consumed, using a flow rate of feed water.

Feed water inlet flow rate is equal to steam flow rate in full load (300MW) stable condition after deducting the continuous blowdown. Therefore flow measurement instrument was installed at the boiler make -up water line and water consumption for soot blowing was measured to determine the steam flow rate. Further analysis was carried out to estimate the boiler make-up water production cost separately.

LVPP uses sea water as the main water resource for the plant water supply and adopting Pretreatment, Ultrafiltration, Reverse Osmosis and Ion Exchanging process to treat water as per the required quality parameters. Unit cost of water production was estimated as covering the all area of water production plant.

Energy loss of the flue gas with soot blowing was calculated for normal routine condition and varies frequencies of soot blowing. Unit cost of energy was determined based on unit cost of coal considering the energy conversion of coal burning process.

Hence, total soot blowing cost was determined considering both cost of steam consumed and cost of loss of flue gas.

3.6. Defining the optimum soot blowing frequency

All the cost were expressed in terms of annual cost and compare at each soot blowing frequency conditions. Finally the best and the most cost effective soot blowing frequency is identified.

CHAPTER 4: RESULTS AND DISCUSSION

4.1. Identification of parameter variation with soot blowing

4.1.1. Observation of key parameters

For the soot blowing process some quantity of main steam was diverted from the intermediate place of superheater panels. Table 4.1 is indicated key parameters of the soot blowing.

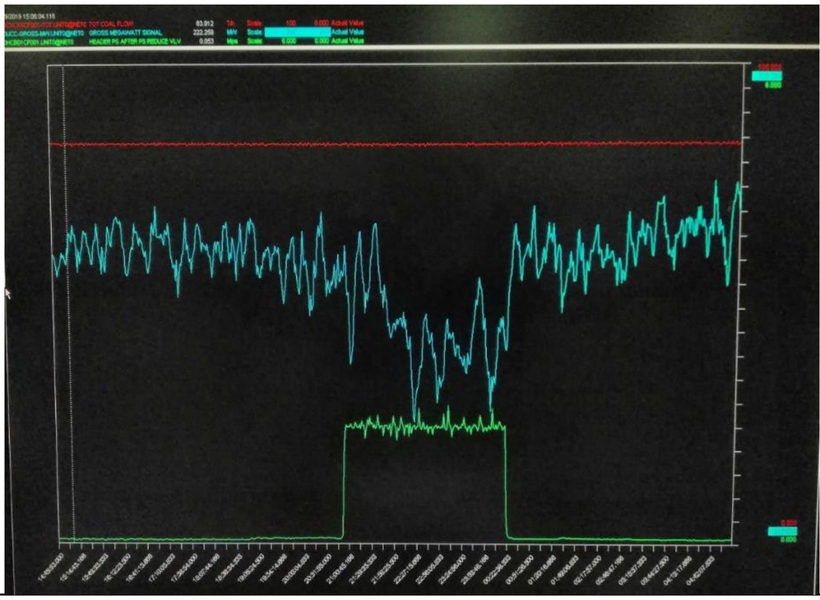
Table 4.1: Key parameters of soot blowing

Parameter	Value	Remarks
Soot blowing steam pressure	1.5 MPa	Instrumental reading
Soot blowing steam temperature	470 °C	Instrumental reading
Steam consumption	10.1 MT/h	Refer Appendix I
Effective time of soot blowing	3 h	Measured value
Total time of soot blowing	5 h	Design parameter

The temperature and pressure of the superheated steam are 470 °C and 1.5 MPa respectively. Since it is practical impossible to measure the steam consumed for soot blowing directly, boiler make up water filling flow rate was measured by newly installed flow meter. Flow meter readings are attached at Appendix I. According to the collected flow readings, the average water consumption for soot blowing was 10.1 MT/h. It is equal to the steam consumption for soot blowing in plant full load (300MW) stable condition after deducting the continuous blow down. Since continuous blowdown is a constant process of the boiler, it can neglect the amount of water which was used for continuous blowdown. Total time consumed for soot blowing is 5 hours as per the design parameters of the boiler. But it was observed by direct reading, that the effective time of soot blowing is only three hours.

4.1.2. Turbine output load (MW) variation with soot blowing

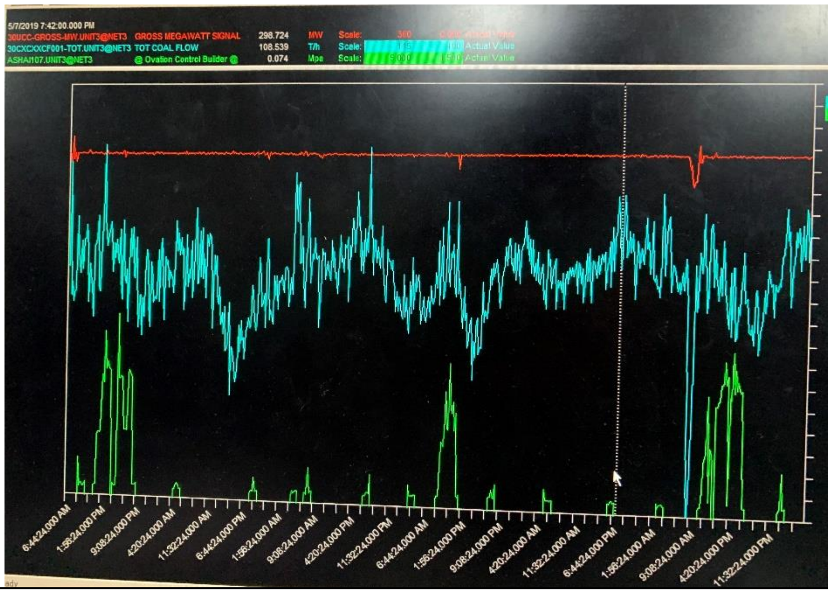
Unit No.1 was selected to study of turbine output load (MW) under the condition of fixed coal flow rate in its boiler operation. Main steam pressure was reduced when soot blowing was in progress. It was observed about the reduction of turbine output load with respect to the boiler main steam pressure under the fixed coal flow rate for five hour time period. Figure 4.1 was clearly indicated of load reduction while soot blowing.



Coal flow rate Load (MW)

Soot blowing steam pressure

Figure 4.1: Load variation (MW) with soot blowing



Load (MW) Coal flow rate

Soot blowing steam pressure

Figure 4.2: Coal flow rate variation with soot blowing

According to figure 4.1 average load without soot blowing was 221.9 MW and average load while soot blowing was 219.46 MW. Hence average reduction during soot blowing operation is 2.4 MW in Unit No.1 at LVPP. For the fixed load condition (Unit No.2 and Unit No.3) additional amount of coal consumed to maintain the constant output load during soot blowing as shown in the figure 4.2.

4.1.2. Variation of flue gas temperature with soot blowing

Flue gas temperature is increased gradually and reduced drastically after soot blowing. Figure 4.3 shows the temperature variation and it can be observed that minimum flue gas temperature is a constant value due to the furnace become soot free condition. Further increment of flue gas temperature is varied with respect to the soot scaling and fouling of the boiler due to the reduction of heat transfer.

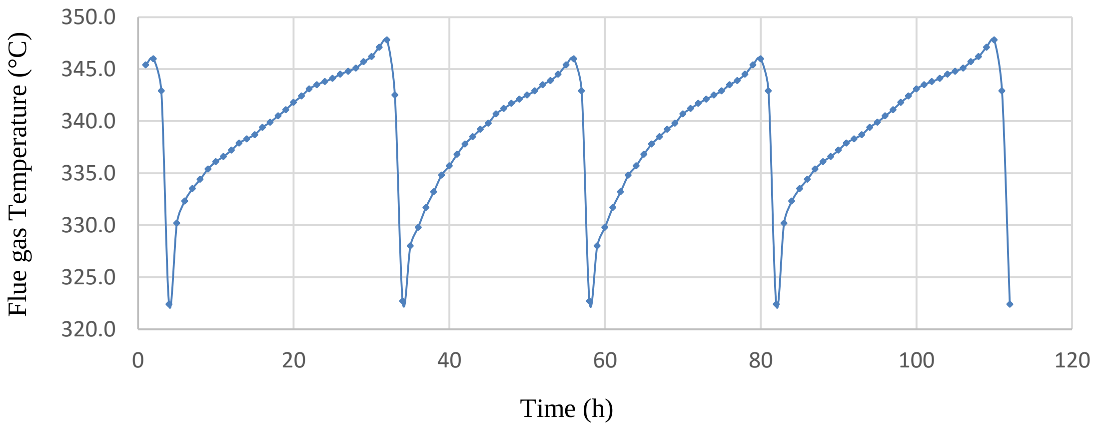


Figure 4.3: Flue gas temperature variation with soot blowing

Same procedure was performed at different soot blowing frequencies such as f= 18 h, f= 24 h, f= 36 h, f= 48 h, f= 54 h, f= 60 h, f= 72 h and normal routine. (Refer Appendix II)

4.2. Boiler efficiency calculation

4.2.1. Fuel analysis

Composition of each element of coal was measured at chemical laboratory in LVPP. Average value of each element was included in table 4.2.

Table 4.2: Chemical analysis data

Element	Short term	Value	Unit
C	MpCF	63.27	mass%
H	MpH2F	4.36	mass%
N	MpN2F	1.43	mass%
O	MpO2F	9.60	mass%
S	MpSF	0.43	mass%
Moisture	MpWF	11.00	mass%
Fixed carbon	MpFc	54.20	mass%
Volatile matter	MpVm	24.50	mass%
Ash	MpAsF	9.91	mass%
Higher healing value	HHVF	25870	kJ/kg

4.2.2. Analysis of atmospheric parameters

Atmospheric parameters were calculated according to the equations which were mentioned in the Chapter 2.6.3.2

Table 4.3: Atmospheric parameters

Parameter	Short term	Value	Unit
Barometric pressure	Pa	100.96	kPa
Dry-bulb temperature	Tdb	27.67	°C
Dry-bulb temperature	TdbF	81.81	F
Wet-bulb temperature	Twb	24.11	C
Relative humidity	Rhm	87.60	%
Saturation pressure of water vapor at Tdb	PsWvTdb	3.71	kPa
Partial pressure of water vapor in air	PpWvA	3.25	kPa
Mass fraction of Moisture in dry air	MFrWDA	0.0207	kg/kg dry air
Mass fraction of Moisture in wet air	MFrWA	0.0202	kg/kg wet air

4.2.3. Analysis of air and flue gas parameters

Variables were determined using both direct readings and results from the equations as mentioned in the Chapter 2.6.3.3.

Table 4.4: Air and flue gas parameters

Air and flue gas parameter	Short term	Value	Unit
Primary air temp. at APH inlet	TAEnP	44.92	°C
Secondary air temp. at APH inlet	TAEnS	30.53	°C
Primary air flow	MFW1	296100	kg/h
Secondary air flow	MFW2	820600	kg/h
Primary air rate	Xpa	0.27	
Secondary air rate	Xsa	0.73	
Air temperature entering the boiler	TMnAEn	34.35	°C
Flue gas temp	TFg	322.40	°C
O2 content	VpO2e	2.72	vol% dry base
O2 content	VpO2	4.49	vol% dry base

4.2.3. Analysis of residue properties

Residue properties were calculated as per the equation derived in Chapter 2.6.3.4.

Table 4.5: Residue data

Residue properties	Short term	Value	Unit
Unburned total carbon in fly ash	MpToCRsfa	1.96	mass%
Unburned total Carbon in bottom ash	MpToCRsba	6.14	mass%
Mass fraction of fly ash	MpRsfa	90.00	mass%
Mass fraction of bottom ash	MpRsba	10.00	mass%
Unburned carbon in residue	MpToCRs	2.38	mass%
Total mass of residue per mass fuel	MFrRs	0.10	kg/kg fuel
Unburned carbon in fuel	MpUbC	0.24	mass%
Carbon burned in fuel	MpCb	63.03	mass%
Carbon burnout	MpCbo	99.62	%
Mass of rate of fly ash	MqRsf	3.5317E-06	kg/kJ
Mass of residue of bottom ash	MqRsb	3.924E-07	kg/kJ

4.2.4. Analysis of combustion properties

Combustion air parameters were calculated as per the equations derived in Chapter 2.6.3.5.

Table 4.6: Combustion properties

Combustion properties	Short term	Value	Unit
Typical value of theoretical air for fuel, ideal	MqThAf	3.24E-04	kg/kJ
Mass of theoretical air corrected	MFrThACr	8.38	kg/kg fuel
Theoretical air corrected	MqThACr	3.23E-04	kg/kJ
Moles of theoretical air required (corrected)	MoThACr	0.29	kmoles/kg fuel
Moles of dry products from fuel combustion	MoDPc	0.053	kmoles/kg fuel
Moles of wet products from fuel combustion	MoWPc	0.081	kmoles/kg fuel
Moles of moisture in air	MoWA	0.033	moles/moles dry air
Excess air at APH inlet	XpAe	16.55	%
Excess air at APH outlet	XpA	30.39	%
Moles wet gas per mass fuel at APH inlet	MoFge	0.37	kmoles/kg fuel
Moles wet gas per mass fuel at APH outlet	MoFg	0.41	kmoles/kg fuel
Mass of dry air at APH inlet	MqDAe	3.76E-04	kg/kJ
Mass of dry air at APH outlet	MqDA	4.21E-04	kg/kJ
Mass of wet air at APH inlet	MqAe	3.84E-04	kg/kJ
Mass of wet air at APH outlet	MqA	4.30E-04	kg/kJ

4.2.5. Analysis of flue gas parameters

Flue gas parameters were derived by the equations as per Chapter 2.6.3.6.

Table 4.7: Flue gas parameters

Flue gas parameter	Short term	Value	Units
Wet gas from fuel	MqFgF	3.47E-05	kg/kJ
Moisture from H_20 in fuel	MqWF	4.25E-06	kg/kJ
Moisture from the combustion of hydrogen in the fuel	MqWH2F	1.51E-05	kg/kJ
Moisture in air at APH inlet	MqWAe	7.78E-06	kg/kJ
Moisture in air at APH outlet	MqWA	8.70E-06	kg/kJ
Total moisture in flue gas at APH inlet	MqWFge	2.71E-05	kg/kJ
Total moisture in flue gas at APH outlet	MqWFg	2.80E-05	kg/kJ
Total wet flue gas weight at APH inlet	MqFge	4.19E-04	kg/kJ
Total wet flue gas weight at APH outlet	MqFg	4.65E-04	kg/kJ
Dry flue gas weight at APH inlet	MqDFge	3.92E-04	kg/kJ
Dry flue gas weight at APH outlet	MqDFg	4.37E-04	kg/kJ

4.2.6. Calculation of heat losses

4.2.6.1. Dry flue gas loss

Dry flue gas loss was calculated using derived equations from Chapter 2.6.3.7.

Table 4.8: Flue gas loss calculation

Parameter	Short term	Value	Unit
Enthalpy of dry air at TFg	HADg	304.34	kJ/kg
Air temperature entering the boiler	TMnAEnK	307.50	K
Air temperature entering the boiler	TMnAEnF	93.82	F
Enthalpy Of dry air at TMnAEn	HADa	9.38	kJ/kg
Enthalpy of water vapor at TFgF	HWvg	574.41	kJ/kg
Enthalpy of water vapor at TMnAEnF	HWva	17.39	kJ/kg
Enthalpy of wet air at TFg	HATFg	309.81	kJ/kg
Enthalpy of wet air at TMnAEn	HAEn	9.54	kJ/kg
Mean Specific heat of wet air	MnCpA	1.0424	kJ/kgK
Corrected flue gas temperature	TFgc	354.73	C
Temperature of flue gas at APH outlet	TFgF	670.52	F
Temperature of flue gas at APH outlet	TK	627.88	K
Enthalpy dry flue gas	HDFg	338.64	kJ/kg
Dry flue gas loss	QpLDFg	13.271	%

4.2.6.1. Loss due to water from fuel

Loss due to water from fuel was calculated by the equations mentioned in Chapter 2.6.3.8.

Table 4.9: Loss calculation for water from fuel

Parameters	Short term	Value	Unit
Enthalpy of water vapor at TFgF	HSt	3184.08	kJ/kg
Reference air temperature	TradF	77	F
Enthalpy of water at TradF	HWRe	104.57	kJ/kg
Loss due to water in fuel	QpLWF	1.309	%

4.2.6.2. Other losses

Other losses were calculated from the equation derived in Chapter 2.6.3. and all values are included in the table 4.10.

Table 4.10: Other losses

Type of loss	**Short term**	**Value**	**Unit**
Loss due to water formed from the combustion of H2 in fuel	QpLH2F	4.638	%
Loss due to moisture in air	QpLWA	0.497	%
Loss due to unburned carbon in residue	QpLUbC	0.314	%
Loss due to surface radiation and convection	QpLSrc	0.210	%
Loss due to unaccounted factor	QpLUm	0.001	%

Sum of losses was expressed in $\sum QpLn$,

$\sum QpLn$= 20.189

Efficiency of the boiler is derived from the Equation 2.50.

$$EFH = 100 - \sum QpLn$$

$$EFH = 100 - 20.241$$

$$EFH = 79.76\ \%$$

In accordance with ASMI PTC4-1998, Maximum boiler efficiency can be determined by mathematical model mentioned in Appendix III. Boiler performance variation for normal routing of soot blowing process was mentioned in figure 4.4.

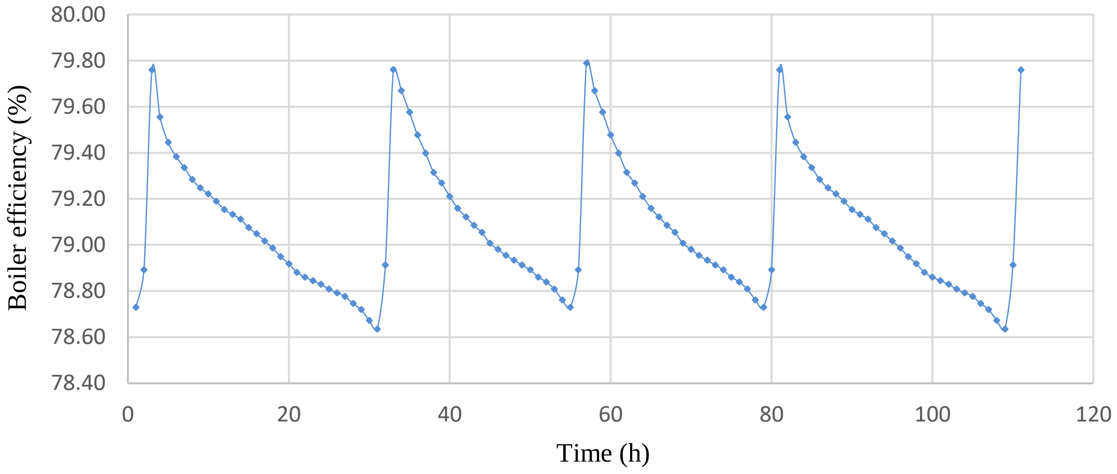


Figure 4.4: Boiler performance variation for normal routine

It can be observed that the boiler reaches its maximum efficiency after soot blowing process completed and it always give same reading. However minimum boiler efficiency is recorded prior to soot blowing process and efficiency drop is increased with time gap in between two soot blowing process.

4.3. Impact on boiler performance with respect to the soot blowing

One of main objective of the research is to identify the impact on boiler performance with respect to the soot blowing frequency. Since the most sensitive parameter due to the soot blowing is flue gas temperature. Therefore variation of boiler performance with respect to the flue gas temperature variation was calculated through the mathematical model (Appendix III). For different soot blowing frequencies, flue gas temperature was measured in order to find out the boiler efficiency (refer Appendix IV).

In a single graph, all boiler efficiencies were plotted to identified behavior at different soot blowing frequencies (refer Appendix V).

4.3. Relationship between coal flow rate and soot blowing frequency

4.3.1. Experimental results

The experiment was conducted for Unit No.3. The average coal flow rate was observed for the frequency of 48 hours and 72 hours by using normal routine of soot blowing operation. Remaining soot blowing frequencies i.e. 18 hours, 24 hours and 60 hours were tested after changing the soot blowing schedule for limited time period. It was identified that average coal flow rates in different soot blowing frequencies as mentioned in the table 4.11. Measured average coal flow rates are attached in Appendix VI.

Table 4. 11: Average coal flow rate for different frequency of soot blowing

Soot Blowing Frequency (f) h	Average Coal Flow Rate (C) MT/h	Remarks
18	108.53	Tested results
24	107.45	Tested results
48	107.80	Results taken from normal routine
60	108.32	Tested results
72	109.85	Results taken from normal routine

Variation of coal flow rate at each soot blowing frequency can be evaluated through the graph mentioned in the figure 4.1. According the figure 4.1 average coal flow rate is higher at both low and high frequencies, than the medium range frequencies. The minimum coal flow rate lies in between 24 and 48 frequency range and a formula was derived to find the average coal flow rate for any frequency of soot blowing.

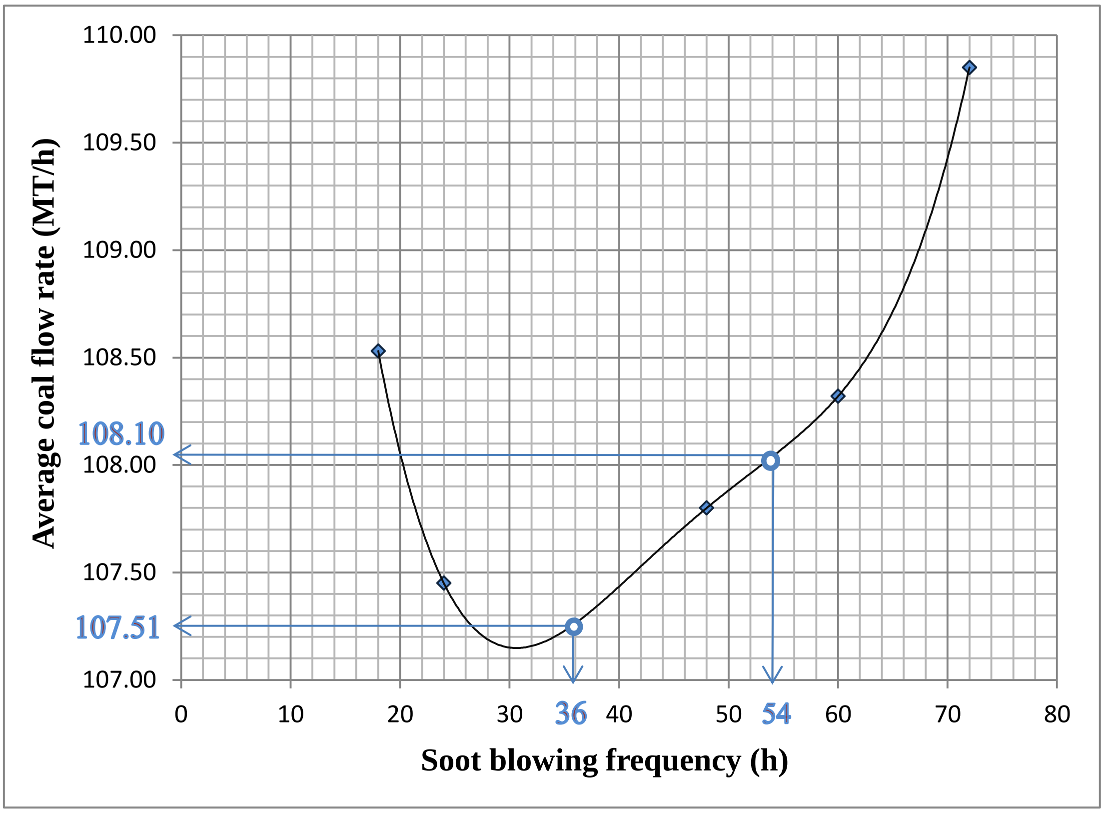


Figure 4.5: Average coal flow rate variation for different frequencies of soot blowing

According to the figure 4.1, coal flow rate with respect to the frequency of soot blowing behave as fourth order polynomial which can be expressed as;

$$C = af^4 + bf^3 + c\,f^2 + df + E \tag{4.1}$$

Where,

C = Average coal flow rate

f = Frequency of soot blowing

a = 4x10^{-6}, b = -0.007, c = 0.0466, d = -1.379, E = 121.8

To validate the equation a cross check was carried out at the frequency of 36 hours and 54 hours. Results calculated by the graph were compared with the actual test results perform that Unit No.3 Comparison is tabulated in the table 4.12.

Table 4. 12: Result comparison

Tested soot blowing frequency	Average actual coal flow rate by experiment (MT/h)	Average coal flow rate from the Equation 4.1 (MT/h)	Error Percentage (%)
36	107.50	107.51	-0.009%
54	107.99	108.10	-0.100%

Further, graph mentioned in figure 4.5 was modified incorporating test results at f =36 h and f =54 h and re-drawn it as in figure 4.6.

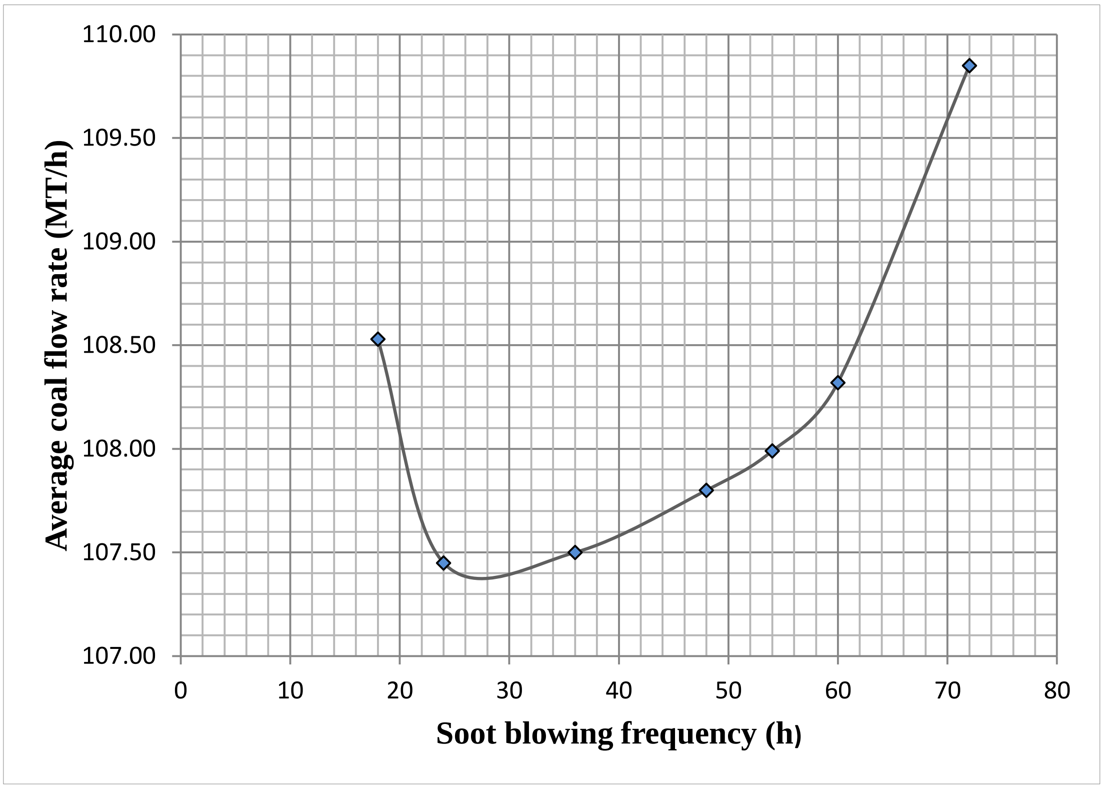


Figure 4.6: Corrected coal flow rate variation for different frequency of soot blowing

Corrected formula was defined in Equation 4.2 for coal flow rate with respect to the frequency of soot blowing using the re-drawn graph.

$$C_c = pf^6 + qf^5 + rf^4 + \ sf^3 + tf^2 + uf + V \tag{4.2}$$

Where,

C_c = Corrected average coal flow rate, f = Frequency of soot blowing

p = 2x10^{-9}, q =-6x10^{-7}, r =8x10^{-5}, s =-0.0054, t =0.2019, u =3.903, V =137.6

According to modified graph soot blowing frequency at minimum coal flow rate can be calculated. However further studies were carried out to identify the optimum soot blowing frequency considering maximum cost saving compare to the normal routine.

4.4. Cost evaluation

4.4.1. Input fuel cost variation for different frequencies of soot blowing

Fuel cost was estimated by assuming the plant is running continuously throughout the year. Unit price of coal is 22.00 Rs/kg as taken from monthly performance report of LVPP.

Annual fuel cost for normal routine of soot blowing is Rs. 21,278,316,159.00 Coal cost for different frequency of soot blowing was estimated and results were compared with the cost of normal routine. As per the table 4.13 which express the annual fuel cost variation, at the higher and lower frequencies fuel cost is significantly higher. The minimum value is lied between range of 24 hours and 36 hours.

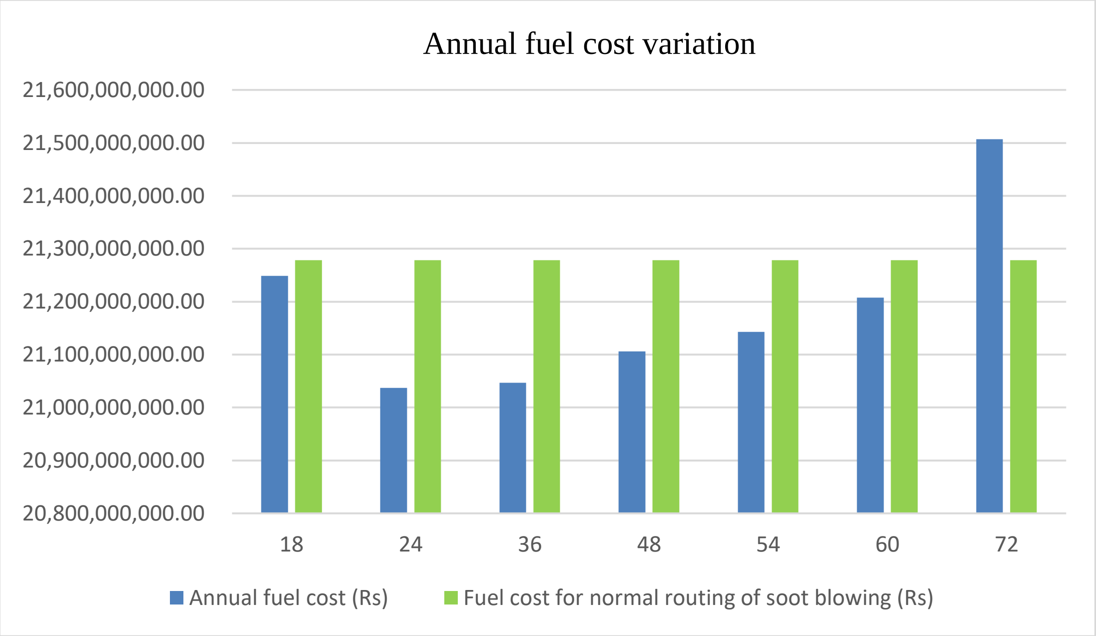


Figure 4.7: Annual fuel cost variation

Fuel cost saving with respect to the normal routing is varied as mentioned in the table 4.14. and figure 4.7. The maximum fuel cost saving can be identified in the frequency of 24 hours.

Table 4.13: Annual fuel cost variation

Soot blowing frequency (h)	Average fuel flow rate (MT/h)	Fuel cost per hour (Rs/h)	Annual fuel cost (Rs)
18	108.53	2,425,645.00	21,248,654,580.00
24	107.45	2,401,507.00	21,037,205,700.00
36	107.50	2,402,625.00	21,046,995,000.00
48	107.80	2,409,330.00	21,105,730,800.00
54	107.99	2,413,576.00	21,142,930,140.00
60	108.32	2,420,952.00	21,207,539,520.00
72	109.85	2,455,147.00	21,507,092,100.00

Comparing both annual fuel cost and cost for normal routing, Fuel cost saving can be obtained as shown in table 4.14.

Table 4.14: Fuel cost variation with respect to the normal routine of soot blowing

Soot blowing frequency	Annual fuel cost (Rs)/A	Annual fuel cost for normal routine (Rs) /B	Fuel cost saving (Rs) C=B-A
18	21,248,654,580.00	21,278,316,159.00	29,661,579.00
24	21,037,205,700.00	21,278,316,159.00	241,110,459.00
36	21,046,995,000.00	21,278,316,159.00	231,321,159.00
48	21,105,730,800.00	21,278,316,159.00	172,585,359.00
54	21,142,930,140.00	21,278,316,159.00	135,386,019.00
60	21,207,539,520.00	21,278,316,159.00	70,776,639.00
72	21,507,092,100.00	21,278,316,159.00	(228,775,941.00)

Fuel cost saving was plotted against soot blowing frequency to obtained the maximum cost saving as shown in figure 4.8.

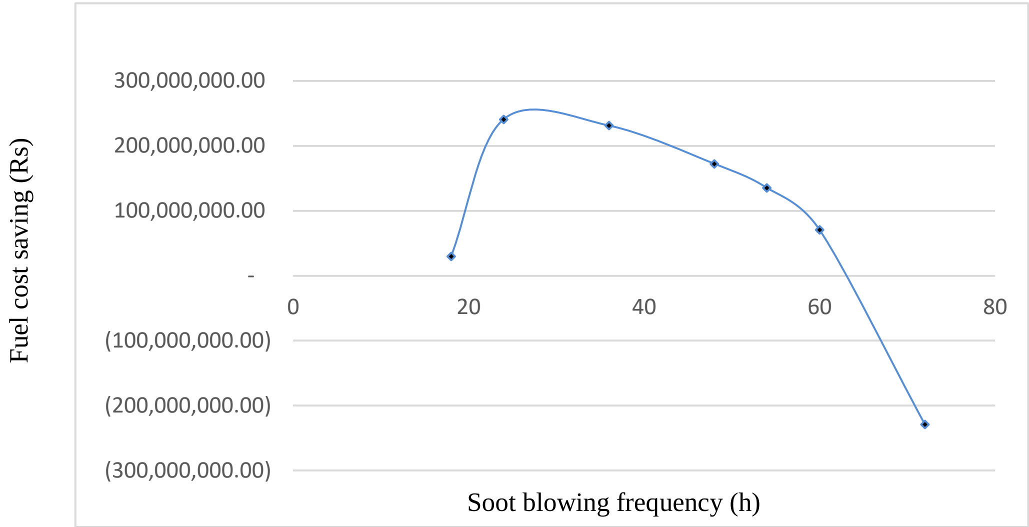


Figure 4.8 : Fuel cost saving with soot blowing frequency

According to the graph maximum input fuel cost saving is occurred at f =24 hours and f =36 hours.

4.4.2. Cost of soot blowing at different frequencies

Energy loss due to flue gas and steam consumption are the main energy consumers for soot blowing. Energy loss due to soot blowing was calculated separately for different frequencies as mentioned in Appendix VII. According to the calculation of flue gas loss, cost incurred can be estimated as in the table 4.15. 1 kJ of energy is equal to Rs.0.000872554 based on the unit price of fuel and GCV of fuel.

Table 4.15: Cost variation for flue gas loss

Soot blowing frequency (h)	Flue gas loss (kJ)	Cost for energy loss due to flue gas per tern (Rs)	Number of terns soot blowing per year	Annual cost for flue gas loss (Rs)
18	129,965,945.00	113,402.00	487	55,226,774.00
24	205,869,888.00	179,633.00	365	65,566,045.00
36	366,161,220.00	319,495.00	243	77,637,285.00
48	563,014,034.00	491,260.00	183	89,900,580.00
54	658,646,013.00	574,704.00	162	93,102,048.00
60	787,871,085.00	687,460.00	146	100,369,160.00
72	1,085,080,457.00	946,791.00	122	115,508,502.00

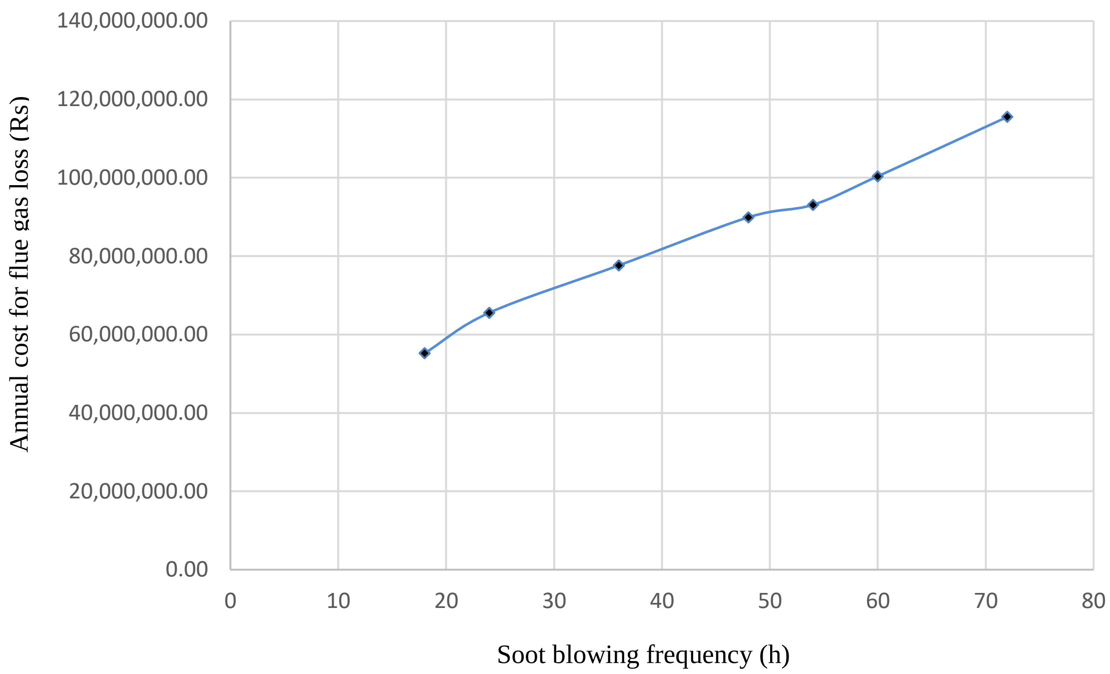


Figure 4.9: Annual cost for flue gas loss for different frequency

Flue gas loss is increased with the frequency of soot blowing and number of terns are decreased with the increase of frequency. However total cost for flue gas loss tends to be increased with frequency.

As calculated in Appendix I steam consumption for soot blowing is 10.1MT/h and cost for production of treated boiler water is Rs. 225.00 per metric ton as calculated in Appendix VIII. Annual cost for steam consumed for different frequencies of soot blowing is mentioned in table 4.16.

Table 4.16: Cost variation for steam consumption

Soot blowing frequency (h)	Number of soot blowing per year	Annual cost for steam consumed for soot blowing (Rs.)
18	487	3,287,250.00
24	365	2,463,750.00
36	243	1,640,250.00
48	183	1,235,250.00
54	162	1,093,500.00
60	146	985,500.00
72	122	823,500.00

Cost for steam consumption is decreased with the frequency of soot blowing due to the decreasing of soot blowing terns.

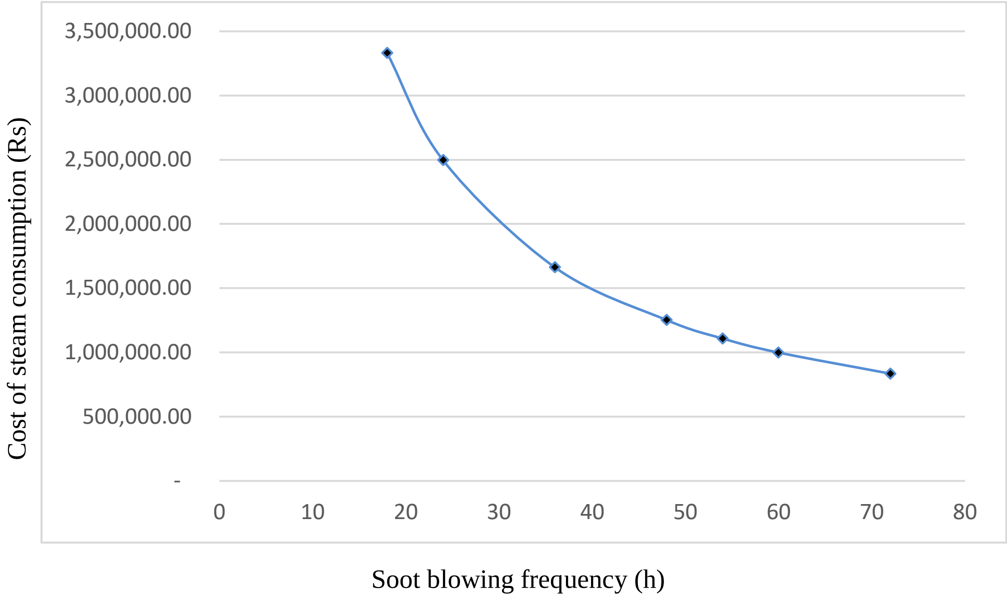


Figure 4.10: Cost variation of steam consumption

Based on the values of table 4.15 and 4.16 total cost for soot blowing can be calculated (Refer table 4.17).

Table 4.17: Total annual cost variation

Soot blowing frequency (h)	**Total cost of soot blowing per year (Rs.)**
18	58,514,024.00
24	68,029,795.00
36	79,277,535.00
48	91,135,830.00
54	94,195,548.00
60	101,354,660.00
72	116,332,002.00

Calculated cost for soot blowing at each frequency can be compared with cost for normal routine.

Similarly to aforementioned calculation total cost for normal routine is identified as Rs.101, 391,183.00 using cost for flue gas loss is Rs.100, 324,203.00 and cost for steam consumed is Rs.1,066,981.00

Figure 4.11 shows the comparison of total soot blowing cost variation at each frequency with respect to the normal routine.

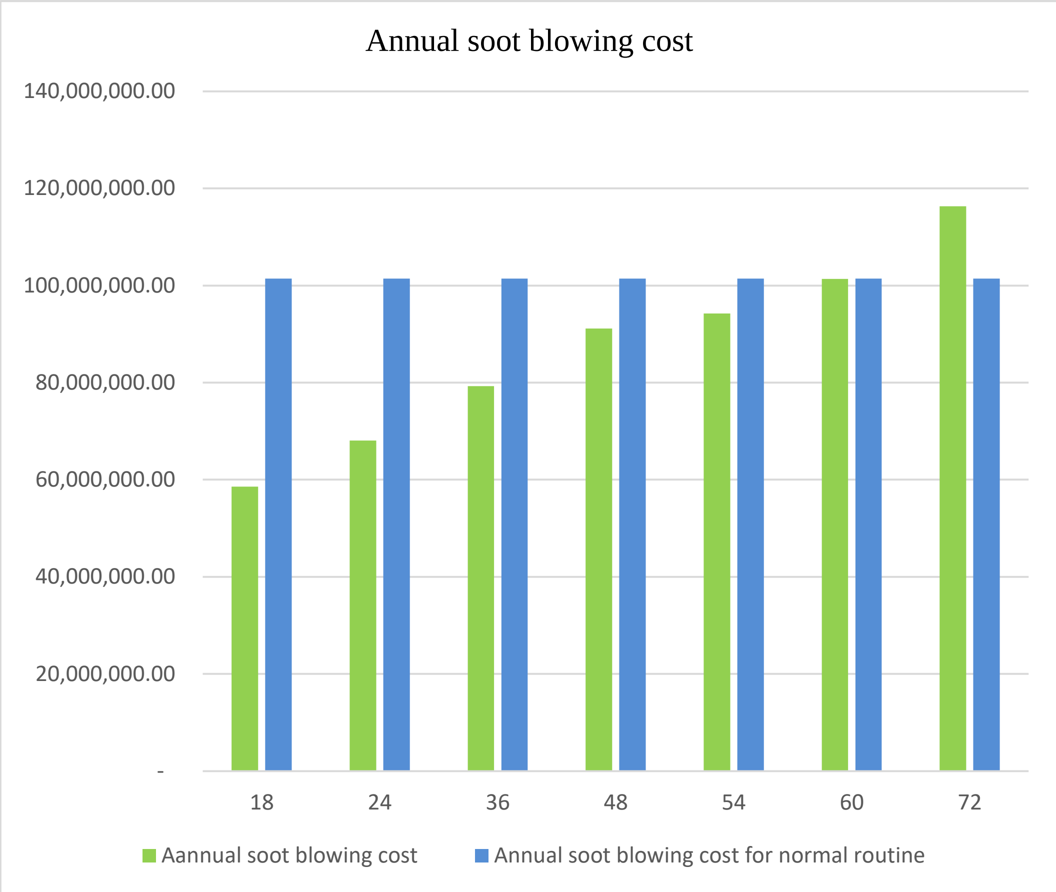


Figure 4.11: Annual soot blowing cost variation

Since flue gas loss has a higher impact over annual soot blowing cost, it can be interpreted that at higher frequencies, it causes higher cost than the normal routine.

4.5. Optimum soot blowing frequency

Effective cost term was introduce to identified impact of both fuel cost and soot blowing cost. It is an indication of actual energy utilized for steam generation of the boiler.

$$Effective\ cost = Fuel\ cost - Soot\ blowing\ cost \tag{4.3}$$

Annual effective cost variation can be obtained for different soot blowing frequencies in terms of effective cost.

Effective cost for normal routine can be calculated by using Equation 4.3.

$$Effective\ cost = 21{,}278{,}316{,}159.00 - 101{,}391{,}183.00$$

$$Effective\ cost = 21{,}176{,}924{,}980.00$$

Similar as normal routine effective cost was calculated for different frequencies (Refer table 4.18)

Table 4.18: Variation of the effective cost saving

Soot blowing frequency (h)	Annual total effective cost for different frequency of soot blowing (Rs)/A	Annual Effective cost for normal routine of soot blowing (Rs.)/B	Annual effective cost saving with respect to the normal routing of soot blowing (Rs)/C=B-A
18	21,190,096,763.00	21,176,924,980.00	(13,171,783.00)
24	20,969,143,342.00	21,176,924,980.00	207,781,638.00
36	20,967,695,581.00	21,176,924,980.00	209,229,399.00
48	21,014,578,543.00	21,176,924,980.00	162,346,437.00
54	21,048,720,039.00	21,176,924,980.00	128,204,941.00
60	21,106,171,766.00	21,176,924,980.00	70,753,209.00
72	21,390,749,128.00	21,176,924,980.00	(213,824,148.00)

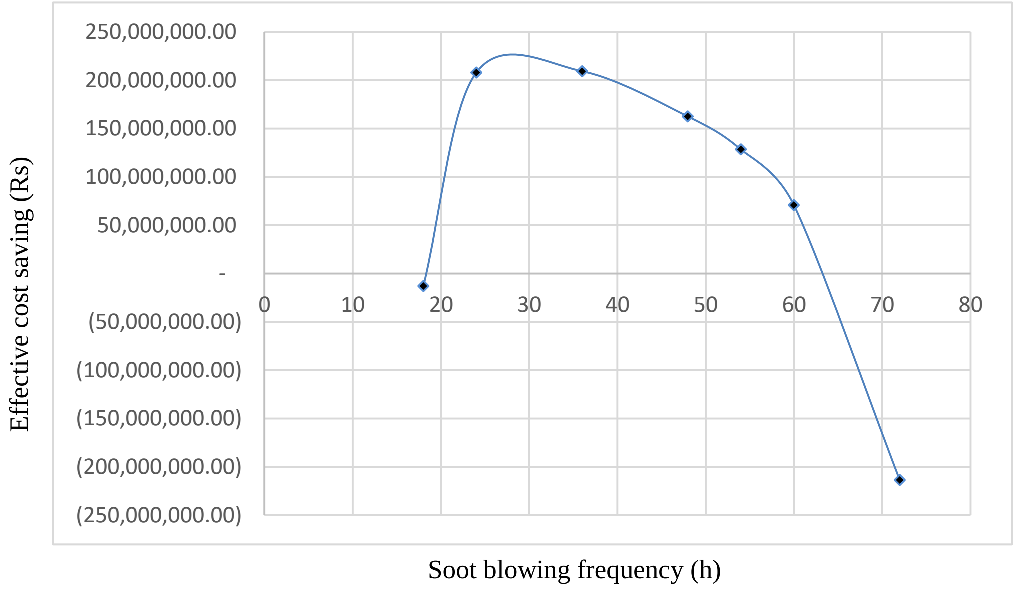


Figure 4. 12: Variation of effective cost saving

Maximum effective cost saving occurred in between f = 24 hours and f = 36 hours.

CHAPTER 5: CONCLUSION AND FUTURE WORK

LVPP is the most critical power station in Sri Lanka which has the ability to provide more than 40% of total power requirement. The main objective of the LVPP is the maintaining an uninterrupted full load condition to meet current power demand. Due to the practical condition, the availability of power has a higher priority than the performance based operation. However it is important to increases the performance also while mitigating the effect from possible energy loss scenarios.

Soot blowing process was identified as one of energy consumable task which required significant amount of energy to conduct and cause an increment in fuel consumption in absentia. As a practice LVPP has followed design soot blowing schedule provided by the contractor without evaluating an optimum condition to suit power plant itself. It was identified that flue gas temperature and coal flow rate are the key parameters with respect to the soot blowing operation and both parameters has a direct impact over boiler efficiency.

A mathematical model was developed to determine boiler performance using ASMI PTC 4- 1988. It is allowed to calculate the boiler efficiency under given input and output parameters. Further maximum boiler efficiency was obtained using the mathematical model as 79.76 %. It was identified that same maximum boiler efficiency can be achieved at different soot blowing frequency and it was noticed at the end of the soot blowing process. Each and every soot blowing process can facilitate the maximum boiler efficiency despite the time duration. It is indicated that the total deposited soot completely removed after the soot blowing process. In addition to that same behaviour of soot deposition in the boiler tubes can be interpreted using the boiler efficiency behaviour.

Relationship between coal flow and frequency of soot blowing is derived by experimental method. Derived equation is;

$$C = 2x\,10^{-9} f^{6} - 6x10^{-7} f^{5} + 8x10^{-5} f^{4} - 0.0054 f^{3} + 0.2019 f^{2} - 3.903f + 137.6$$

Maximum input fuel cost saving comparing with normal routine can be achieved in the range of f = 24 hours and f = 36 hours. To obtain optimum soot blowing frequency effective cost was defined and f = 24 hours and f =36 hours gives the maximum effective cost saving.

As a practice f = 24 hours is easy to imply at daily routine operation compare to the f = 36 hours. Hence it is recommended to perform soot blowing process as a daily basis.

This studies were carried out under the assumption of plant full load continuous running. This results are applicable for similar boilers under identical conditions. Future studies are required for different load and boiler condition to identify the optimum soot blowing frequency.

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