OPTIMIZATION OF FUEL IN SATURATED STEAM BOILER

By

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Certificate

This is to certify that work on this thesis has been carried out by **Uzair Ibrahim** and completed under supervision of **Dr. Sarah Farrukh and Dr. Bilal Khan Niazi** in School of Chemical and Materials Engineering (SCME), National University of Sciences and Technology, H-12, Islamabad, Pakistan.

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Dedication

This work is dedicated to my beloved parents and teachers.

Acknowledgements

I would like to acknowledge and thank the dedicated faculty at our School of Chemical and Materials Engineering. This project would not have been possible without their guidance. To mention in specific, Dr. Sarah Farukh and Dr. Bilal Khan Niazi, who served as a source of extreme guidance and encouragement for the entirety of our project. Also, I would like to thank my Industrial Supervisor, Engineer Mirza Muhammad Nabeel at Engro Foods, for his continuous cooperation.
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I am extremely indebted to my parents for believing in me and for helping me in achieving my dreams.

Abstract

Boilers are vital components in any industry. Usually, a fluid like water is used to generate high pressure steam for the heating purposes. In a food industry, there is a large requirement of this high-pressure steam. Boiler is one of the main equipment that requires high fuel consumption. Therefore, fuel optimization is very significant for efficient processing. The aim of this project is to optimize fuel consumption in saturated steam boiler. For this purpose preheated air is fed to the furnace and excess air is controlled to enhance the boiler efficiency by minimizing the losses, thus leading to fuel optimization. Moreover, the make-up water is also preheated in condensing economizer to reduce the energy requirements in the boiler.

Saturated steam boilers use heat from the furnace to generate steam. Major components of the fired tube boiler are economizer i.e. a tubular type heat exchanger which preheats the BFW to economize the process. A furnace with convective and radiative zones, in which the combustion takes place. Economy is the most important factor in the industry so fuel consumption is optimized by certain methods which is the main focus of this project.

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1 Introduction

The Saturated Steam Boiler generates 10 tons/hr of steam at a pressure of 11 bar. A fraction of the steam generated goes to the deaerator and the rest goes to the process plant for heating purposes. During the process, steam produced is saturated steam. This steam is produced in fire heated saturated steam boiler by heat exchange between water (make-up plus condensate returns) and the flue gas generated in furnace.

The project is aimed at optimizing the fuel consumption. Currently, the boiler is having an efficiency of 76% while operating on natural gas as fuel. This makes us to focus on remaining 24% boiler's efficiency which can be improved. 15% excess air is used for achieving complete combustion which in turn prevents us to have sooty appearances or explosive natured flue gas presence. A large percentage of flue gas turns to decrease the efficiency and hence by controlling the flue gas percentage and finding an optimal point, we can enhance the efficiency of the boiler.

Another option is to recover the heat from stack flue gases. This heat can be used to preheat the combustion air. It has been found that with every 22^0C increase in combustion air temperature, the efficiency of boiler increases by 1%. Moreover, make-up water is also pre-heated to reduce overall heat losses.

2 Literature Review

2.1 Boiler

2.1.1 Introduction:

Boiler is an equipment used to generate high pressure and high temperature steam from water. Steam is the most common fluid for industrial processing, heating, and power generation applications. It is used as a heating source for many process heating heat exchangers, reactors, reboilers and heat transfer equipment etc. Boilers are also sometimes called as the steam generators as the main purpose of the boiler is to convert the liquid into the vapor. The most important part of boiler is furnace where the burning of fuel results in the production of heat and flue gases. This combustion heat converts the water into steam.

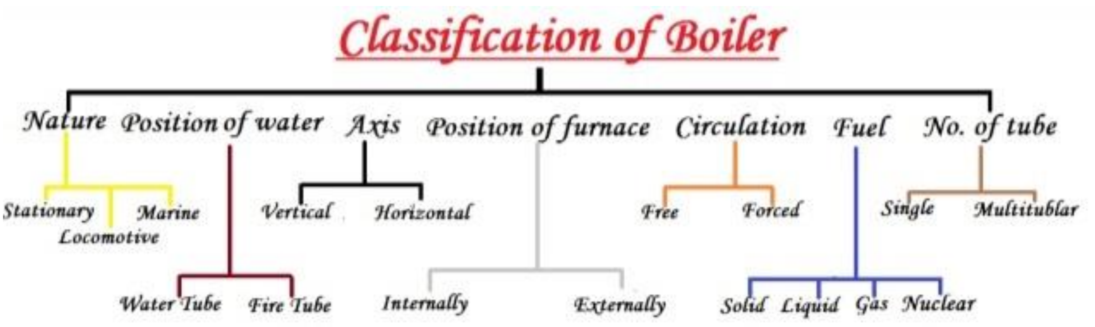


Figure 2.1 Classification of Boilers

Boilers are classified in different ways including position of water, position of furnace, type of fuel, number of tubes and circulation methods as shown in Fig. 2.1.

2.1.2 Classification On The Basis Of Configuration:

On the basis of configuration and position of water, steam boilers are mainly categorized into two types:

- Water tube boiler
- Fire tube boiler

Water Tube Boiler

Water tube boiler is a high-pressure boiler in which water circulates in the tubes of the boiler also known as water tubes. The heat is provided by the flue gas produced during the combustion of fuel in the furnace of boiler. In case of water tube boiler, hot flue gases are present in shell side. Water absorbs the heat from hot gases enter the steam drum by heated by natural motion and any amount of left over water goes back to the tubes for further heating and the steam is supplied to the industry. However, in case of superheated steam it goes to super heater and is converted into superheated steam.

Water tube boilers are mostly used for high steam production. Fig. 2.2 explains steam generation in the tubes from combustion gases.

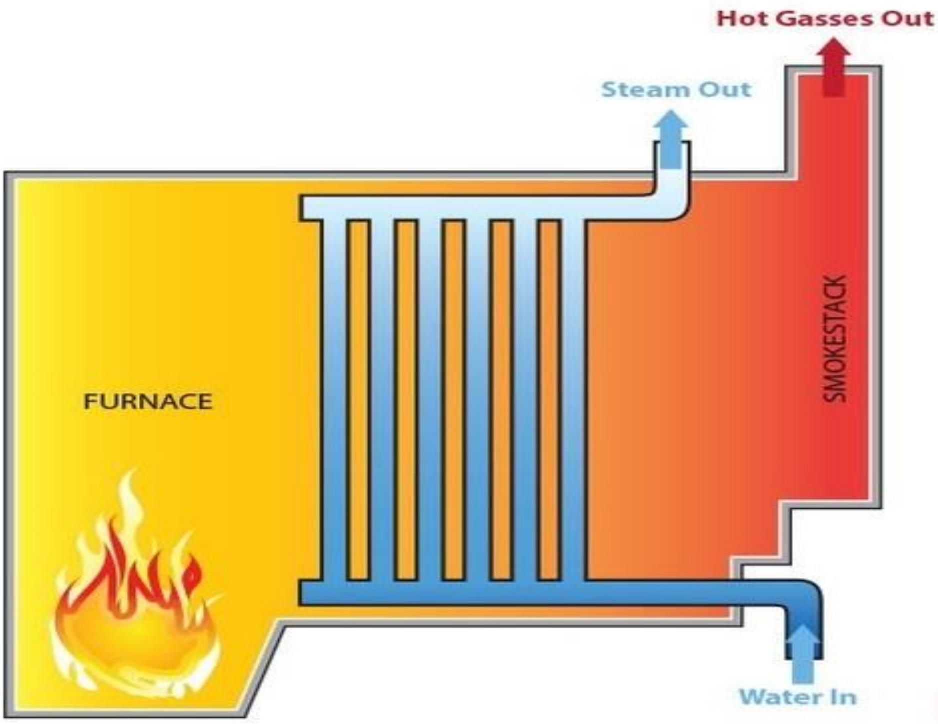


Figure 2.2 Water Tube Boiler

Fire Tube Boiler

In fire tube boiler hot combustion gases are present in tubes while water in present in shell side surrounding the tubes. Water is heated by the heat of flue gases present in tubes through conduction. These boilers are better than water tube boilers because of the presence of a large number of tubes present in the boiler. These tubes provides greater surface area for heat transfer, resulting in better efficiency.

Fig. 2.3 shows a common fire tube boiler.

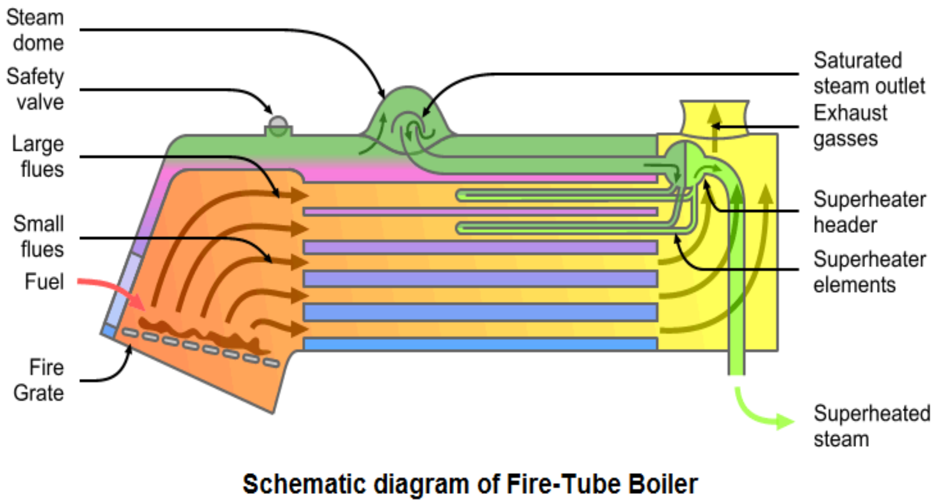


Figure 2.3 Fire Tube Boiler

Depending upon the application fire tube or water tube boiler is used in industry. A brief comparison between the two is given below.

TABLE 2.1 A Comparison of Fire Tube and Water Tube Boilers

Variable	Fire tube boiler	Water tube boiler
Gas flow	Small—less than 50,000 lb/h	50,000 to millions of lb/h
Gas inlet temperature	Low to adiabatic combustion	Low to adiabatic combustion
Gas pressure	High—even as high as 2000 psig	Generally less than 2 psig
Firing	Possible	Possible
Type of heating surface	Bare tube	Bare and finned tubes
Superheater location	At inlet or exit of boiler	Anywhere in the gas path using screen section
Water inventory	High	Low
Heat flux-steam side	Generally low	Can be high with finned tubes
Multiple steam pressure	No	Yes
Soot blower location	Inlet or exit of boiler	Anywhere inside boiler surfaces
Multiple modules	No	Yes

The boiler at Engro Foods is Fire tube that produces saturated steam.

2.1.3 Classification On The Basis Of Circulation:

Boiler are also classified on the basis of circulation system used. There are two types of systems. Natural or Forced.

Natural Circulation:

In natural circulation boilers have vertical tubes and horizontal gas flow orientation. These units employ the difference in density between water and steam to drive the steam water mixture through the tubes and risers and back to steam drum. The phenomenon is called thermos-syphoning.

Forced Circulation:

In forced Circulation units the water tubes are while the gas flow is in vertical direction. Steam-water mixture circulates through the tubes by a pump. Steam separates from the mixture and goes to the steam header.

2.1.4 Classification On The Basis Of Application:

Boilers can be classified into three types on basis of their application.

- Utility steam boiler
- Waste heat recovery boiler
- Auxiliary boiler

Utility Steam Boiler

Utility steam boiler produces steam for the whole plant unit. The water tubes in the boiler are in the form of spiral tubes joined in one single tube. A pump is used for forced circulation of fluid. Because of very small diameters of the tubes the risk of explosions is reduced when operating at high pressures.

Waste Heat Recovery Boiler

Waste heat recovery boiler utilizes the waste process streams like waste combustion gases for steam production. These could be stack flue gases coming from gas turbines and main boiler. These boilers increase the efficiency of the system by decreasing the capital cost and hence making the system cost effective and energy efficient.

Auxiliary Boiler

Auxiliary boiler is installed with the main boiler and serve as extra boiler. It is used only for the start-up of the steam production and generates steam when the main boiler is shut down for the maintenance purposes.

3 Process Description

3.1 Process Flow Diagram

Fig. 3.1 (a) shown below is the process flow diagram of saturated steam boiler currently installed at Engro Foods. Fig. 3.1(b) shows the proposed process flow diagram with the proposed air preheater to the furnace and condensing economizer to preheat the make-up water coming from RO Plant. The combustion air being fed to the furnace is first preheated by the flue gases from the economizer and increasing the temperature of air from 30°C to 96°C. This pre-heated air takes less fuel energy than the cold air resulting in the combustion efficiency increase of about 3%. Also, excess air reduction of 5% and preheating of make-up water has contributed to the overall combustion efficiency increase of 4%.

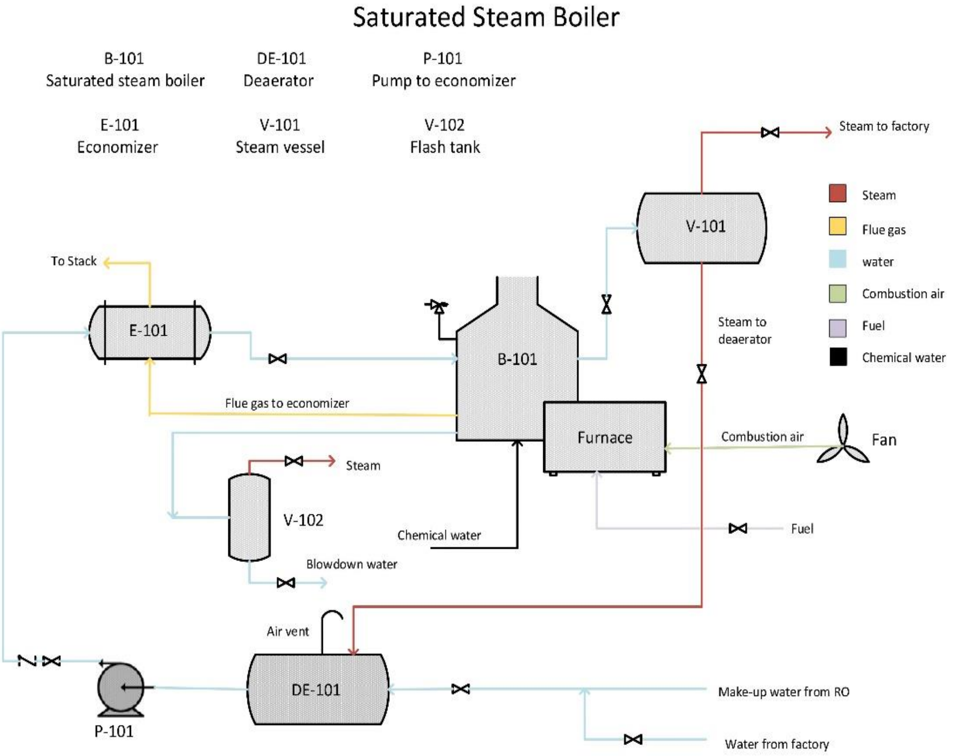


Figure 3.1a Process Flow Diagram (Existing)

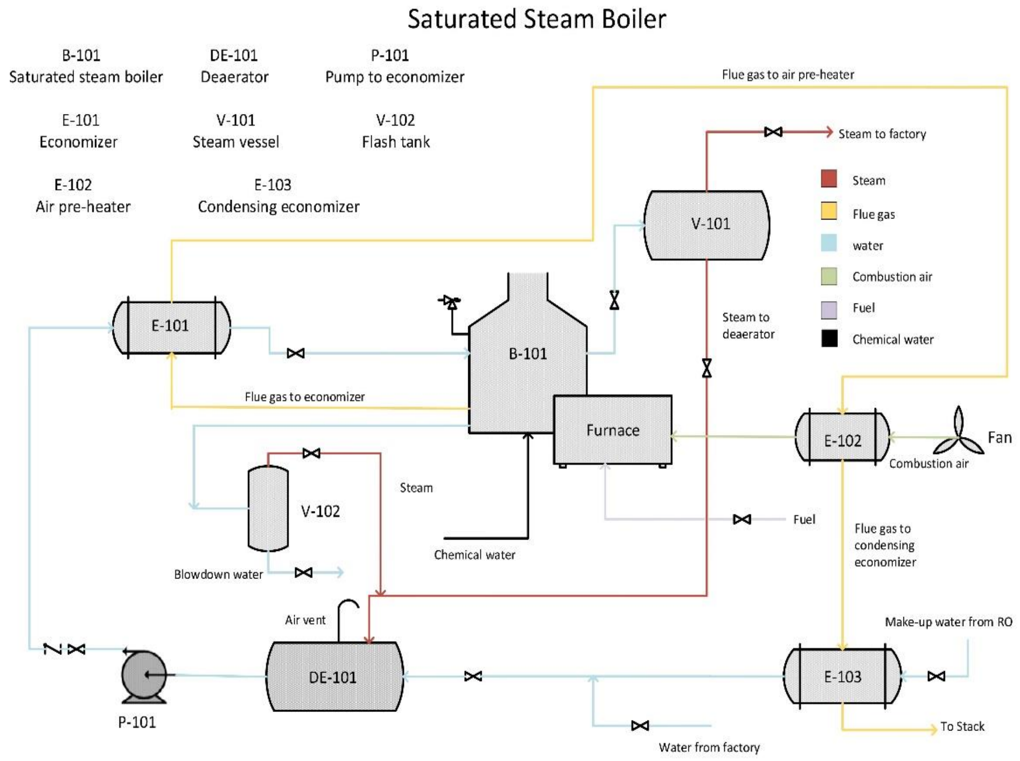


Figure 3.1b Process Flow Diagram (Proposed)

3.2 Deaerator:

The cycle starts with preheated make up water coming from RO plant and condensate returns entering the deaerator. The main purpose of deaerator is to remove unwanted dissolved oxygen and other gasses from the feed water. This is done by the adding steam and removing the unwanted gases through the vent. The presence of dissolved gases in water, mainly oxygen and carbon dioxide, promotes the risk of corrosion. Oxygen is more violent of the two. Therefore, oxygen removal is highly important. Even little presence of oxygen gas instigates serious corrosion and other severe problems. Deaeration process reduces the risk of corrosion by eliminating the dissolved gases and oxygen water.

The deaerator works on the principle of Henry's Law. According to this law there exists a direct relation between the solubility of any gas in liquid and the partial pressure of gas in the liquid. Thus, on addition of steam in water its temperature increases resulting decrease in the solubility of dissolved gases which are then removed in the vent.

Steam is used for deaerating because steam is readily available and it reduces the solubility of gases in the liquid. Moreover, most of the steam used to scrub water is condensed and becomes a part of the deaerated water.

3.2.1 Types of Deaerator:

Deaerators can be classified into three main types:

1. Spray type deaerator
2. Tray type deaerator
3. Vacuum type deaerator

Spray Type Deaerator:
Spray type deaerator has both horizontal and vertical vessel. These vessels act as feed water tank and deaeration section. A standard spray type deaerator comprise of a pre-heating section and a deaeration section. These two sections are separated by a medium caleed baffle. From the sparger a low-pressure steam enters the vessel from the base and the boiler feed water is sprayed over it the heat transfer between water nad steam warm up the boiler feed water to a saturation temperature. Moreover, the unwanted gases are removed from the water through a vent present at the upper side of the vessel.

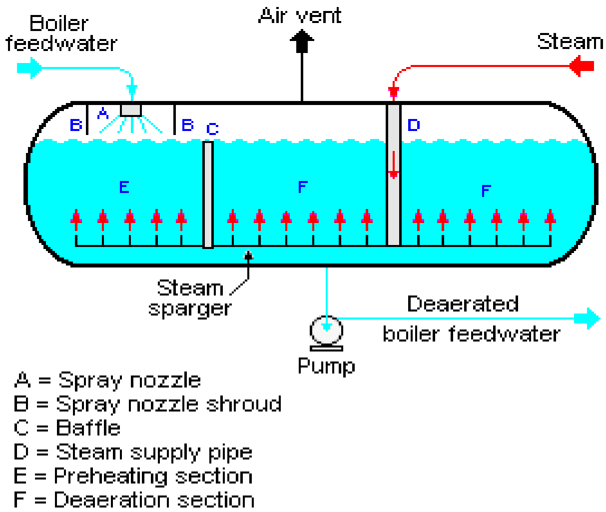


Figure 3.2 Spray Type Deaerator

Tray Type Deaerator:
Tray type deaerator also known as the Cascade type deaerator is vertical deaeration section fixed over the horizontal vessel serving as a deaerated storage feed water tank. The boiler feed water enters the vertical deaeration that is placed above the perforated

tray and is designed to flow downwards the perforation. Low-pressure steam passes through the perforation tray and moves upward through the perforation. Packed beds designs are preferred over perforated tray since they provide better contact between water and steam. The steam injected increase the temperature, thus reducing the gas solubility. Unwanted gases are removed through the vent present at the top of the vessel.

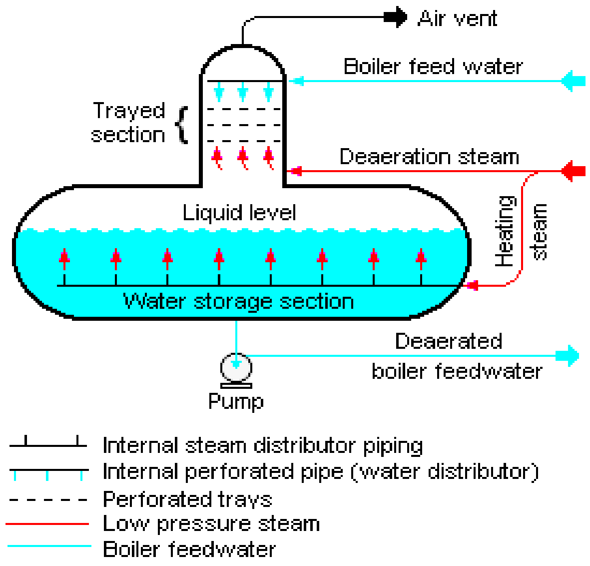


Figure 3.3 Tray Type Deaerator

Vacuum Type Deaerator:

Deaerator is normally constructed in a way that the deaeration tank contains galvanized steel or stainless steel. Internally, the tank is furnished with a transitional bottom, underneath which is a reservoir of deaerated water fixed. Filters are fitted on top of the transitional bottom. A vacuum pump also known as liquid ring pump is attached with the deaerator for the purpose of sucking the released dissolved gasses. Thus maintaining a negative pressure in the deaerator system to increase the discharge of dissolved gasses through the boiler feed water.

After the deaerator has been connected and fixed, the initializing test of safe valve should take place in the local for avoiding the issue of being jammed. When the turbine functions, the two deaerator water boilers should be activated in parallel. The steam pressure, water level, and temperature should be kept the same and they cannot be operated individually. Before delivering water and steam to the deaerator, the vent valve of deaerator should be untied first. One part of the pressure amendable device and the water level controller is used mutually for the two deaerators. Before the vacuum is not established in the condenser, prevent the steam and water of deaerator drain to the condenser. When the turbine shuts down and the principal feed water pump is closed, the plant start-up and shutdown feed-water pump should retain operation for some time to calm the key coolant system. In that moment, the deaerator should be functioning continuously till the plant start-up and the shutdown feed water pump discontinues. To prevent surpassing of the design stress the deaerator has to be furnished with two safety valves and to intercept the vacuum the deaerator should be equipped with vacuum breakers. Deaerator also performs the function of an additional storage device, which delivers reserve amount of boiler feed water during upstream water supply breakdown for temporary period normally for about 20 minutes. In few Plants, Deaerator is also helpful for treating oxygen-scavenging substances like Hydrazine or Hydroquinone.

3.3 Feed Water Economizer:

An economizer is a heat recovery equipment that preheats the boiler flow water by using waste flue gases coming out of boiler. This helps to reduce energy losses by recovering a sizable portion from waste flue gases. Feed Water Economizer is a shell and tube type heat exchanger in which water is present in tubes while flue gases flow outside in the shell. Feed water economizer preheats the water before sending it to the boiler, thus reducing the energy demands of the boiler. Moreover, it also decrease the stack temperature of flue gases while avoiding the low temperature corrosion. An economizer can reduce the operational costs by 5-10% and pays for itself in less than two years by recovering waste heat energy.

3.4 Boiler:

A boiler is an equipment that converts the water into steam. Boiler is a necessity in every industry because of high steam demand in various operations. At Engro Foods, saturated steam boiler generates 10 tons of saturated steam at 11 bar pressure. A part of this steam is sent to deaerator while the major part is goes to the industry for heating purposes through steam headers.

3.5 Air Preheater:

Air preheater is basically a shell and tube type heat exchanger used to preheat the combustion air before sending it to the furnace. The air from the atmosphere is heated using the waste flue gases coming from feed water economizer. According to a study, every 22^{o}C temperature increase in air results in 1% efficiency increase. This preheated air also maintains the furnace temperature thus reducing fuel consumption.

3.6 Condensing Economizer:

Condensing economizer utilizes the heat from the stack flue gases coming from air preheater to increase the temperature of make-up water. This further increases the efficiency of the boiler by preheating the make-up water. The makeup water instead of going directly to the deaerator goes to the condensing economizer first where it is preheated and then sent to the deaerator.

4 Material Balance

4.1 Deaerator:

Steam in calculation:

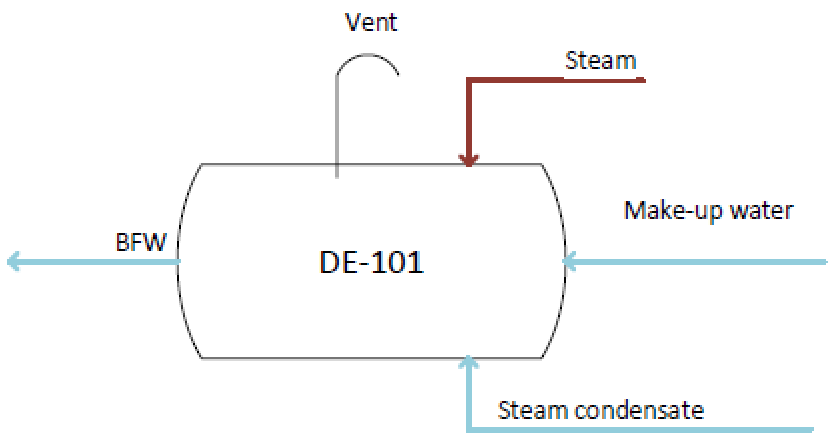


Figure 4.1Deaerator

$$M_S = Mass\ flow\ of\ Steam\ In$$

$$= \frac{M_W(H_O - H_W)}{(H_S - H_O)}$$

$$= \frac{9701.85(459.25 - 312.63)}{(2779.66 - 459.25)}$$

$$M_S = 613.3\ {}^{kg}/_{hr}$$

$$Mass\ Flowrate\ of\ Vent = 1\%\ of\ Steam\ Added$$

$$= 613.3 \times \frac{1}{100}$$

$$= 6.13\ {}^{kg}/_{hr}$$

Table 4.1 (a) Deaerator Balance

DEAERATOR MASS BALANCE	
Streams	
M_W = mass of inlet water (kg/hr)	9701.85
H_W = Enthalpy of Inlet water (KJ/kg)	312.63
H_S = Enthalpy of Steam at the given Temperature	2779.66
H_O = Enthalpy of the outlet water at specified temperature	459.25
Mass flow of steam added	613.30
M_V = Mass flowrate of Vent = (1 percent of Steam added)	6.13

Overall Material Balance on Deaerator:

Table 4.1 (b) Deaerator Balance

Inlet		**Outlet**	
Stream	Flowrate kg/hr	Stream	Flowrate kg/hr
Inlet water	9646.85	Boiler Feed water	10253.83
Steam	613.3	Vent(1% of Steam added)	6.13

4.2 Boiler:

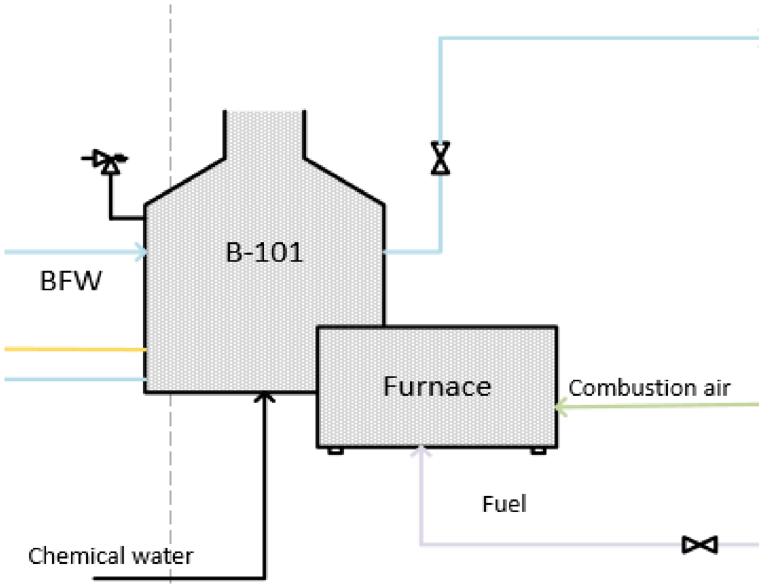


Figure 4.2 Boiler

Table 4.2 (a) Boiler

Material Balance on Boiler			
Inlet		**Outlet**	
Stream	Flowrate (kg/hr)	**Stream**	Flowrate (kg/hr)
Boiler Feed Water	10253.83	**Blowdown**	552.17
Chemical water	0.196	**Steam Generated**	9701.85
10254.02		**10254.02**	

$$Blowdown = BFW + Chemical\ Water - Steam\ Generated$$

$$= 10253.83 + 0.196 - 9701.85$$

$$= 552.17\ \frac{kg}{hr}$$

TDS Balance:

Table 4.2 (b) TDS

TDS BALANCE			
Inlet		**Outlet**	
Boiler Water (kg/hr)	10253.83	**Blowdown (kg/hr)**	552.17
TDS ppm	50	**TDS**	928.5

4.3 Boiler Economizer:

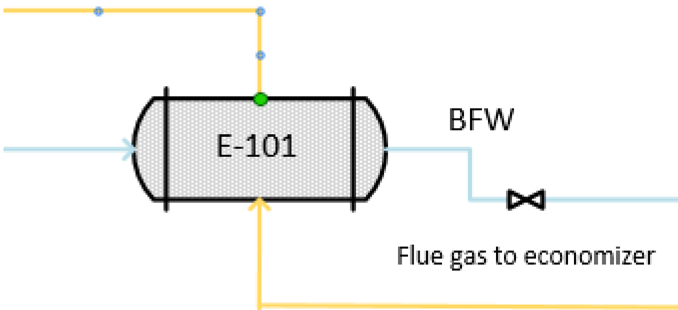


Fig 4.3 Feed Water Economizer

Table 4.3 Economizer

Material Balance on Economizer			
Inlet		**Outlet**	
Stream	Flowrate(kg/hr)	**Stream**	Flowrate (kg/hr)
Boiler Feed Water	10253.83	**Boiler Feed water out**	10253.83
Flue gas in	11850.43	**Flue gas out**	11850.43
22104.26		**22104.26**	

4.4 Condensing Economizer:

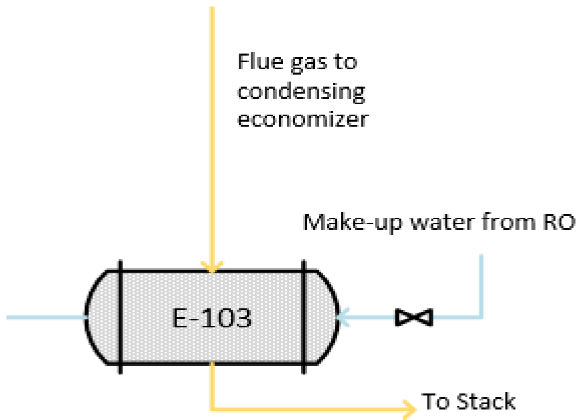


Fig 4.4 Condensing Economizer

Table 4.4 Balance on condensing economizer

Condensing Economizer			
Inlet		**Outlet**	
Flue gas in (kg/hr)	11850.43	**Flue gas in (kg/hr)**	11850.43
Water In (kg/hr)	3573	**Water out (kg/hr)**	3573
15423.43		**15423.43**	

4.5 Air Preheater:

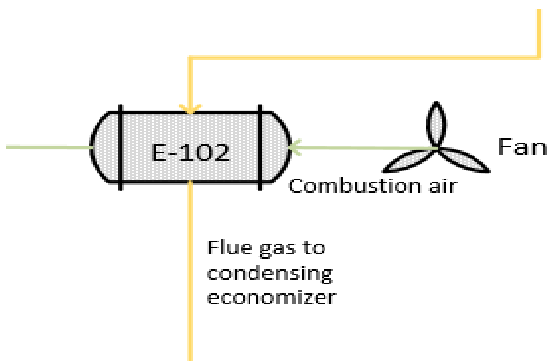


Fig 4.4 Air Preheater

Table 4.5 Balance on air preheater

Air Preheater			
Inlet		**Outlet**	
Flue gas in (kg/hr)	11850.43	**Flue gas in (kg/hr)**	11850.43
Air In (kg/hr)	11018.19	**Air out (kg/hr)**	11018.19
22868.62		**22868.62**	

4.6 Furnace Balance:

Furnace balance was applied in order to calculate the composition of flue gas leaving the boiler furnace. The consumption of fuel **1404.06 m^3/hr** and its consumption of was provided by the industry.

Table 4.6 a Fuel composition

Fuel Composition	
Component	**Percentage**
Methane	76.97
Ethane	0.09
Carbon dioxide	0.39
Nitrogen	22.53
Hexane	0.02

4.4.1 Reactions:

The combustion reactions of fuel and purge gases were as follows:

$$CH_4 + 3/2O_2 \rightarrow CO + 2H_2O$$

$$C_2H_6 + 5/2O_2 \rightarrow 2CO + 3H_2O$$

$$C_6H_{14} + 13/2O_2 \rightarrow 6CO + 7H_2O$$

$$H_2 + 1/2O_2 \rightarrow H_2O$$

$$CO + 1/2O_2 \rightarrow CO_2$$

By combining the amounts of carbon and hydrogen in both fuel and purge gas, we found out the total moles present.

Fuel-air Mixture Composition		
Component	**Kmoles**	**Percentage**
Methane	33.13	32.59
Ethane	0.01	0.01
Carbon dioxide	0.04	0.04
Nitrogen	19.01	18.70
Hexane	0.001	0.001
Argon	1.48	1.46
Hydrogen	47.97	47.19

With 88 % combustion efficiency

The total moles of oxygen required were found out by the stoichiometric equations shown above.

Moles of O_2 required = 90.29 kmoles

The percentage of excess air used was 15% and using this, the extra moles of oxygen provided by the excess air were provided.

Moles of O_2 supplied by 15 percent excess air = 103.83 kmoles

Similarly, the amount of total nitrogen was found out which was the sum of nitrogen in the fuel and purge gas and the amount of N2 present in air.

Total N_2 = N_2 in fuel + N_2 in Air = 409.62 kmoles.

Similarly, the percentage of unreacted O2 which was coming out in the flue gas was also calculated by the difference of oxygen supplied and reacted.

O_2 in flue gas= 24.43 kmoles

H_2O produced = 100.54 kmoles

CO Unreacted = 3.98 kmoles

CO_2 Produced = 29.22 kmoles

Moles of Argon in Fuel = 1.48 kmoles

Thus the composition of the flue gas came out to be as follows and similarly the mass flow rates were also calculated.

Table 4.6 c Fuel gas composition

Flue Gas Composition			
Component	**Moles (kmol)**	**Mole Percentage**	**Mass flow (kg/hr)**
Carbon dioxide	29.22	5.13	1285.68
Carbon monoxide	3.98	0.70	111.44
Oxygen	24.43	4.29	781.76
Nitrogen	409.62	71.96	11469.36
Argon	1.48	0.26	59.20
Water	100.54	17.66	1809.92
		Total	11850.43

4.7 Blowdown Flash Tank:

The blowdown flash tank uses the continuous blowdown to draw the useful amount of heat.

4.7.1 Percentage of flash Steam:

First of all the percentage of flash steam was calculated by using the formula:

$$Percentage\ of\ Flash\ Steam = \frac{H_b - H_f}{V_t}$$

Where,

H_b = specific enthalpy of water at boiler pressure = 781.65 kJ/kg

H_f = specific enthalpy of water at flash pressure = 560.1 kJ/kg

V_t = latent heat of vapourization at flash prssure = 2201.59 kJ/kg

Thus, Percentage of Flash Steam = 10.06 %

Table 4.7 a Blowdown balance

Blowdown Flash Tank		
Mass in (kg/hr)	**Mass out (kg/hr)**	
Blowdown water	**Flash Steam**	**Waste water**
552.17	55.55	496.62
552.17	552.17	

4.7.2 TDS Balance:

Table 4.7 b TDS balance

TDS Balance			
In		**Out**	
Boiler Feed Water (kg/hr)	**TDS (ppm)**	**Blowdown (kg/hr)**	**TDS (ppm)**
10253.83	50	496.62	1045.21

5 Energy Balance

5.1 Deaerator

Table 5.1 Deaerator Energy Balance

Deaerator	
Mass flowrate of makeup water (kg/hr)	3573.0
Mass flowrate of steam in (kg/hr)	613.30
Mass flowrate of steam condensate (kg/hr)	6073.79
Mass flowrate of water out (kg/hr)	10253.18
Enthalpy of makeup water (kJ/kg)	351.75
Enthalpy of steam in (kJ/kg)	2779.66
Enthalpy of steam condensate (kJ/kg)	361.83
Enthalpy of water out (kJ/kg)	499.13
Heat rate of makeup water (kJ/hr)	1.256E+06
Heat rate of steam in (kJ/hr)	1.704E+06
Heat rate of steam condensate (kJ/hr)	2.197E+06
Heat rate of water out (kJ/hr)	5.117E+06
Heat rate of vent (kJ/hr)	4.11E+03

Known Values:

$$\boldsymbol{Mass\ flowrate\ of\ make\ up\ Water = 3573\ \frac{kg}{hr}}$$

$$\boldsymbol{Enthaply\ of\ make\ up\ water = 351.75\ \frac{kJ}{kg}}$$

Unknown Values:

$$\boldsymbol{Heat\ rate\ of\ water\ in}$$
$$= \boldsymbol{Mass\ flowrate\ of\ water\ in \times Enthalpy\ of\ water\ in}$$
$$= \boldsymbol{3573 \times 351.}75$$
$$= \boldsymbol{1256802.75\ \frac{kJ}{hr}}$$

Known Values:

$$\boldsymbol{Mass\ flowrate\ of\ steam\ in = 613.30\ \frac{kg}{hr}}$$
$$\boldsymbol{Enthalpy\ of\ steam\ in = 2779.66\ \frac{kJ}{kg}}$$

Unknown Values:

$$\boldsymbol{Heat\ rate\ of\ steam\ in}$$
$$= \boldsymbol{Mass\ flowrate\ of\ steam\ in \times Enthalpy\ of\ steam\ in}$$
$$= \boldsymbol{613.30 \times 2779.66}$$
$$= \boldsymbol{1704765.48\ \frac{kJ}{hr}}$$

Known Values:

$$\boldsymbol{Mass\ flowrate\ of\ steam\ condensate = 6073\frac{kg}{hr}}$$
$$\boldsymbol{Enthalpy\ of\ steam\ condensate =\ 361.83\ \frac{kJ}{kg}}$$

Unknown Values:

$$\boldsymbol{Heat\ rate\ \ = Mass\ flowrate\ steam\ condensate\ in}$$
$$\boldsymbol{\times Enthalpy\ of\ steam\ condensate}$$
$$= \boldsymbol{6073 \times 361.83}$$
$$= \boldsymbol{2197393.59\ \frac{kJ}{hr}}$$

Known Values:

$$\boldsymbol{Mass\ flowrate\ of\ water\ out = 10253.18\frac{kg}{hr}}$$

$$\boldsymbol{Enthalpy\ of\ water\ out} = \mathbf{499.13}\ \frac{\boldsymbol{kJ}}{\boldsymbol{kg}}$$

Unknown Values:

$$\boldsymbol{Heat\ rate}\ = \boldsymbol{Mass\ flowrate\ of\ water\ out} \times \boldsymbol{Enthalpy\ of\ water\ out}$$
$$= \mathbf{10253.18} \times \mathbf{499.13}$$
$$= \mathbf{2197393.59}\ \frac{\boldsymbol{kJ}}{\boldsymbol{hr}}$$

Known Values:

$$\boldsymbol{Heat\ rate\ of\ water\ in} = \mathbf{1006240}\ \frac{\boldsymbol{kJ}}{\boldsymbol{hr}}$$

$$\boldsymbol{Heat\ rate\ of\ steam\ in} = \mathbf{1006390}\ \frac{\boldsymbol{kJ}}{\boldsymbol{hr}}$$

$$\boldsymbol{Heat\ rate\ of\ boiler\ feed} = \mathbf{2011225}\ \frac{\boldsymbol{kJ}}{\boldsymbol{hr}}$$

Unknown Values:

$$\boldsymbol{Heat\ rate\ of\ vent}$$
$$= (\boldsymbol{heat\ rate\ of\ makeup\ water} + \boldsymbol{heat\ rate\ of\ steam}$$
$$+ \boldsymbol{heat\ rate\ of\ steam\ condensate}) - \boldsymbol{Heat\ rate\ of\ boiler}$$
$$= \mathbf{256802.75} + \mathbf{1704765.48} + \mathbf{2197393.59} - \mathbf{5117669.73.59}$$
$$= \mathbf{4110.78}\ \frac{\boldsymbol{kJ}}{\boldsymbol{hr}}$$

5.2 Boiler Feed Water Pump:

Calculation for enthalpy change:

Known Values:

$$\boldsymbol{Temperature} = \mathbf{392.06}\ \boldsymbol{K}$$

$$\boldsymbol{Specific\ Volume} = \mathbf{1052.02}\frac{\boldsymbol{m^3}}{\boldsymbol{kg}}$$

$$\boldsymbol{Coefficient\ of\ volume\ expansion} = \mathbf{0.00086}$$

$$\boldsymbol{Inlet\ Pressure = 192.91\ kPa}$$

$$\boldsymbol{Outlet\ Pressure = 1490.99\ kPa}$$

Unknown Values:

$$\boldsymbol{Enthalpy\ Change} = \frac{\boldsymbol{Sp.Vol \times (1 - coefficeint\ of\ expansion \times Temp) \times (\Delta P)}}{\boldsymbol{10^6}}$$

$$= \frac{\boldsymbol{1052.02 \times \left(1 - (0.00086 \times 392.06)\right) - (1490.99 - 192.91)}}{\boldsymbol{10^6}}$$

$$= \boldsymbol{1.36\ \frac{kJ}{kg}}$$

Table 5.2 Pump Energy Balance

PUMP	
Mass flowrate	10253.18
Temperature (K)	392.06
Specific Volume (m^3/kg)	1052.02
Coefficient of volume expansion (1/K)	0.00086
Inlet Pressure (kPa)	192.91
Outlet Pressure (kPa)	1490.99
Enthalpy change (kJ/kg)	0.31
Work (kJ/hr)	10930.43

Calculation for Work Done by Pump:

Known Values:

$$\boldsymbol{Mass\ Flowrate\ of\ BFW = 10253.85\ \frac{kg}{hr}}$$

$$\boldsymbol{Enthalpy\ Change = 1.36\ \frac{kJ}{kg}}$$

$$\boldsymbol{Efficiency = 75\%}$$

Unknown values:

$$\boldsymbol{Pump\ Work = \frac{(Mass\ flowrate\ of\ BFW \times Enthalpy\ Change)}{Efficiency}}$$

$$\boldsymbol{= \frac{4356.79 \times 0.61}{0.75}}$$

$$\boldsymbol{= 18593.65\ \frac{kJ}{hr}}$$

5.3 Boiler Economizer

Table 5.3 Boiler Economizer Energy Balance

Boiler Economizer	
Water Temp in, °C	118.9
Water Temp out, °C	145.0
Flue gas in, °C	301.1
Flue gas out, °C	214.2
Enthalpy of water in, (kJ/kg)	499.13
mass flowrate of water, (kg/hr)	10253.18
Enthalpy of water out, (kJ/kg)	610.78
Flue gas flow(kg/hr)	11850.43
Sp. Heat of flue gas (kJ / kg K)	1.11
Q absorbed by water (kJ/hr)	1.14E+06
Delta T for flue gas (°C)	86.9

Calculation for Heat Absorbed in Water:

Known Values:

$$\boldsymbol{Enthalpy\ of\ Water\ out = 610.78\ \frac{kJ}{kg}}$$

$$\boldsymbol{Enthalpy\ of\ water\ in = 499.13\ \frac{kJ}{kg}}$$

$$\boldsymbol{Mass\ flowrate\ of\ water = 10253.18\ \frac{kg}{hr}}$$

Unknown Values

$$\boldsymbol{Heat\ Absorbed\ by\ water}$$
$$\boldsymbol{= Mass\ flowrate\ of\ water\ in \times Change\ in\ enthalpy}$$
$$= 1\boldsymbol{0253.18} \times (\boldsymbol{610.78 - 499.13})$$
$$= \boldsymbol{1144767.55\ \frac{kJ}{hr}}$$

Calculation for Change in Temperature of Flue Gas:

Known Values:

$$\boldsymbol{Q\ absorbed\ by\ water = 1144767.55\ \frac{kJ}{hr}}$$

$$\boldsymbol{Sp.Heat\ of\ flue\ gas = 1.11\ \frac{kJ}{kgK}}$$

$$\boldsymbol{Flowrate\ of\ flue\ gas = 11850.43\ \frac{kg}{hr}}$$

Unknown Values:

$$\boldsymbol{Change\ in\ Temp\ of\ FG = \frac{(Heat\ absorbed\ by\ water)}{(FG\ flowrate \times FG\ Sp.Heat)}}$$
$$= \frac{\boldsymbol{1144767.55}}{(\boldsymbol{1.11} \times \boldsymbol{11850.43})}$$
$$= \boldsymbol{86.9}\ ℃$$

5.4 Boiler

Table 5.4 Boiler Energy Balance

Boiler	
Steam Temp. °C	184.6
Steam Pressure barg	11.0
Steam Flow (kg/hr)	9701.85
Boiler Feed water Temp. °C	145.0
Boiler Feed water press. barg	7.5
Enthalpy of Steam (kJ/kg)	2779.66
Enthalpy of Feed water (kJ/g)	610.78
Flue gas flow(kg/hr)	11850.43
Sp. Heat of flue gas	1.15
Total heat input in boiler(kJ/hr)	2.91E+07
Total heat out from boiler (KJ/hr)	2.11E+07
Boiler efficiency (%)	80

Calculation for Total Heat Input in Boiler:

Known Values:

$$\boldsymbol{Fowrate\ of\ fuel = 828.48\ \frac{kg}{hr}}$$

$$\boldsymbol{HHV\ of\ fuel = 35100\frac{kJ}{kg}}$$

Unknown Values:

$$\textbf{Total Heat Input in Boiler} = \textbf{Fowrate of fuel X HHV of fuel}$$

$$= \mathbf{828.48 \times 35100}$$

$$= \mathbf{2.91E + 07\ \frac{kJ}{hr}}$$

Calculation for Total heat out from Boiler:

Known Values:

$$\textbf{Enthalpy of feed water} = \mathbf{610.78\ \frac{kJ}{kg}}$$

$$\textbf{Enthalpy of steam} = \mathbf{2779.66\ \frac{kJ}{kg}}$$

$$\textbf{Steam flowrate} = \mathbf{9701.85\ \frac{kg}{hr}}$$

Unknown Values:

$$\textbf{Heat out} = \mathbf{M_S(H_s - H_{BFW})}$$

$$= \mathbf{(2779.66 - 610.73) \times 9701.85}$$

$$= \mathbf{2.11E + 07\ \frac{kJ}{hr}}$$

5.5 Air Preheater

Calculation for Heat Absorbed in Air:

Known Values:

$$\textbf{Inlet air Temp.°C} = \mathbf{30\ °C}$$

$$\textbf{Outlet air Temp.°C} = \mathbf{96\ °C}$$

$$\textbf{Mass flowrate of air} = \mathbf{11818.19\ \frac{kg}{hr}}$$

Unknown Values

$$\textbf{Heat Absorbed by } air$$

$$= \textbf{Mass flowrate of air} \times \textbf{Sp. Heat} \times \textbf{Change in Temp.}$$

$$= \mathbf{11818.19 \times 1.005 \times (96 - 30)}$$

$$= \mathbf{783900.54\ \frac{kJ}{hr}}$$

Table 5.5 Air Preheater Energy Balance

Air Preheater	
Inlet air Temp. °C	30.0
Outlet air Temp. °C	96.0
Air flow rate (Kg/hr)	11018.19
Sp. Heat of air	1.005
Flue gas inlet Temp. °C	214.2
Flue gas outlet Temp. °C	159.21
Flue gas flow(kg/hr)	11850.43
Sp. Heat of flue gas	1.11
Heat absorbed by water(kJ/kg)	881648.90
Delta T for flue gases °C	54.9

Calculation for Change in Temperature of Flue Gas:

Known Values:

$$\boldsymbol{Q\ absorbed\ by\ air = 783900.54\,\frac{kJ}{hr}}$$

$$\boldsymbol{Sp.Heat\ of\ flue\ gas = 1.11\ \frac{kJ}{kgK}}$$

$$\boldsymbol{Flowrate\ of\ flue\ gas = 11850.43\ \frac{kg}{hr}}$$

Unknown Values:

$$\boldsymbol{Change\ in\ Temp\ of\ FG = \frac{(Heat\ absorbed\ by\ air)}{(FG\ flowrate \times FG\ Sp.Heat)}}$$

$$= \boldsymbol{\frac{881648.90}{(1.11 \times 11850.43)}}$$

$$= \mathbf{54.9}\ ℃$$

5.6 Condensing Economizer

Table 5.6 Condensing Economizer Energy Balance

Condensing Economizer	
Inlet water Temp. °C	25.0
Outlet water Temp. °C	84.0
Water flow rate (Kg/hr)	3573.19
Enthalpy of inlet water (kJ/kg)	105.01
Enthalpy of outlet water (kJ/g)	351.75
Flue gas inlet Temp. °C	159.21
Flue gas outlet Temp. °C	91.57
Flue gas flow(kg/hr)	11850.43
Sp. Heat of flue gas	1.11
Heat absorbed by water(kJ/kg)	881648.90
Delta T for flue gases °C	67.60

Calculation for Heat Absorbed in Water:

Known Values:

$$\boldsymbol{Enthalpy\ of\ Water\ out = 351.75\ \frac{kJ}{kg}}$$

$$\boldsymbol{Enthalpy\ of\ water\ in = 105.01\ \frac{kJ}{kg}}$$

$$\boldsymbol{Mass\ flowrate\ of\ water = 3573.19\ \frac{kg}{hr}}$$

Unknown Values

$$\boldsymbol{Heat\ Absorbed\ by\ water}$$
$$= \boldsymbol{Mass\ flowrate\ of\ water\ in} \times \boldsymbol{Change\ in\ enthalpy}$$
$$= \mathbf{3573.19} \times (\mathbf{351.75 - 105.01})$$
$$= \mathbf{881648.90}\ \frac{\boldsymbol{kJ}}{\boldsymbol{hr}}$$

Calculation for Change in Temperature of Flue Gas:

Known Values:

$$\boldsymbol{Q\ absorbed\ by\ water} = \mathbf{881648.90}\frac{\boldsymbol{kJ}}{\boldsymbol{hr}}$$
$$\boldsymbol{Sp.Heat\ of\ flue\ gas} = \mathbf{1.11}\ \frac{\boldsymbol{kJ}}{\boldsymbol{kgK}}$$
$$\boldsymbol{Flowrate\ of\ flue\ gas} = \mathbf{11850.43}\ \frac{\boldsymbol{kg}}{\boldsymbol{hr}}$$

Unknown Values:

$$\boldsymbol{Change\ in\ Temp\ of\ FG} = \frac{(\boldsymbol{Heat\ absorbed\ by\ water})}{(\boldsymbol{FG\ flowrate} \times \boldsymbol{FG\ Sp.Heat})}$$
$$= \frac{\mathbf{881648.90}}{(\mathbf{1.11} \times \mathbf{11850.43})}$$
$$= \mathbf{67.6}\ ^{\circ}\mathrm{C}$$

6 Design and Sizing

6.1 Boiler Economizer

Service	Boiler Economizer
Type	Floating Head Heat Exchanger
Fluid Allocation	Tube Side = Water
	Shell Side = Flue Gases

Tube Side Water

$\boldsymbol{T_{in} = 119\,°C}$ $\boldsymbol{T_{out} = 145\,°C}$ $\boldsymbol{Massflowrate = 10253.18\,\frac{kg}{hr}}$

$\boldsymbol{T_{avg} = 132\,°C}$

Shell Side Flue Gas

$\boldsymbol{T_{in} = 301\,°C}$ $\boldsymbol{T_{out} = 214\,°C}$ $\boldsymbol{Massflowrate = 11850.43\,\frac{kg}{hr}}$

$\boldsymbol{T_{avg} = 257.5\,°C}$

6.1.1 Properties of Shell and Tube Side Fluid

Physical Properties of Water

Physical Property	Unit	Tube Side Water
Density (ρ)	kg/m^3	934.62
Specific Heat (C_P)	kJ/kg .°C	4.200
Viscosity (μ)	mNs/m^2	0.800
Thermal Conductivity (k)	W/m°C	0.68

Assumption		
No of Passes (N_P)		4
Fouling Factor (h_d) **(from table 6 a)**	W/m^2.°C	3,000

Physical Properties of Flue gas

Physical Property	**Unit**	**Flue Gas**
Density (ρ)	kg/m^3	0.68
Specific Heat (cp)	kJ/kg°C	1.15
Viscosity (μ)	mNs/m^2	0.025
Thermal Conductivity (k)	W/m°C	0.0377
Assumption		
No of Passes (N_P)		2
Fouling Factor (h_d) (from table 6 a)	W/m^2.°C	4,000

We assume our heat transfer coefficient $\boldsymbol{U = 200\,\frac{W}{m^2C}}$ (from table 6 c)

LMTD

$$\boldsymbol{LMTD = \frac{\Delta T2 - \Delta T1}{\ln(\frac{\Delta T2}{\Delta T1})}}$$

$$\Delta T1 = 301 - 145 = 156°C$$

$$\Delta T2 = 214 - 119 = 95C$$

$$LMTD = 122.98°C$$

Corrected LMTD

$$R = \frac{T1 - T2}{t2 - t1}$$

$$R = 2.3$$

$$S = \frac{t2 - t1}{T1 - t1}$$

$$S = 0.14$$

$$\Delta Tm = Ft\ \Delta Tlm$$

$$\Delta Tm = 92.24\ C$$

Where Ft is found from Figure 6 a

6.1.1.2 Heat Duty and Heat transfer Area:

$$Q = mC\Delta T$$

$$A = \frac{Q}{U\Delta Tlm}$$

	Units	Tube	Shell
Flow rate (m)	kg/h	10253.18	11850.43
Heat Duty (Q)	kW	311.01	400

$$A = 39.42m^2$$

6.1.1.3 Tube Size and Tube Layout

Material of Construction of Tube: **Carbon Steel**

$$do = 25mm$$

$$P_t = triangular\ pitch$$

$$L = 1.830\ m$$

$$BWG = 16$$

$$d_i = 16mm$$

Calculations

Property	*Value*	*Unit*
Tube Pitch (P_t)	31.250	Mm
Area of one tube (A_1)	143.655	mm^2
No of tubes (N_t)	275	
Tube/pass	69	
Tube cross sectional area (A_C)	200.960	mm^2
Area per pass	0.01386	m^2
Water mass velocity (V_t)	20.549	kg/sm^2
Water Linear Velocity (u_t)	0.02	m/s
Renoyld Number (Re)	374	
L/d_i	114.375	
Tube side coefficient (h_i)	739.2	$W/m^2.°C$

$$Tube\ Pitch = 1.25\ d_O$$

$$A = \pi dL$$

$$A_C = \frac{\pi}{4d^2}$$

$$Re = \frac{p \times d_i \times u_t}{\mu}$$

$$h_i = \frac{4200(1.35 + 0.02Vt)ut^{0.8}}{d_i^{0.2}}$$

6.1.1.4Bundle and Shell Diameter

Assumptions

$$K_1 = 0.175$$

$$n_1 = 2.285$$

(From table 6 c)

Bundle Dia Clearance (mm) (from fig 6 c)	**BDC**	**63**
Baffle Cut		25%
Heat Transfer Factor (from fig 6 f)	j_h	0.003

Calculations

$$D_b = d_o(\frac{N_t}{K_1})^{1/n_1}$$

Hence Bundle Diameter = **627mm**

$$D_s = BDC + D_b$$

Shell Diameter is therefore **690 mm**

$$Baffle\ Spacing = 0.2\ \times D_s$$

Hence Baffle Spacing (lb) is **138mm**

To calculate Shell Area

$$A_S = \frac{(p_t - d_o)D_s \times l_b}{p_t}$$

$$A_S = 44436.17\ mm$$

Equivalent Diameter (mm)	**D_e**	**22.19**
Mass Velocity	G_s	442.64
Volumetric Flow rate (kg/hr)	V_s	11850.85
Velocity (kg/sm^2)	U_s	741.14
Renoyld Number	Re	388,219
Thermal Conductivity (W/m°C)	K_w	32
Prandtl Number	P_r	0.9
Shell Side Coefficient (W/m2°C)	H_s	2148

For an equilateral triangle pitch arrangement

$$d_e = \frac{4(\frac{p_t}{2} \times 0.87 p_t - \frac{1}{2}\pi \frac{{d_O}^2}{4})}{\pi d_o}$$

$$u_S = \frac{G_s}{\rho}$$

$$h_o = \frac{k_f}{d_i} \times j_h Re \quad Pr^{0.33}$$

6.1.1.5 Overall Heat Transfer Coefficient

$$\frac{1}{U_o} = \frac{1}{h_o} + \frac{1}{h_{od}} + \frac{d_o \ln(\frac{d_o}{d_i})}{h_o} + \frac{d_o}{d_i} \times \frac{1}{h_{id}} + \frac{d_o}{d_i} \times \frac{1}{h_i}$$

Overall Heat Transfer Coefficient	**1/U**	**0.00237993**	
	U	420.18	$W/m^2.°C$

6.1.1.6Pressure Drop
Tube Side Pressure Drop Calculation

$$\Delta \boldsymbol{P_t} = \boldsymbol{N_p}(\boldsymbol{8j_f} \times \frac{\boldsymbol{L}}{\boldsymbol{d_i}} \times \frac{\boldsymbol{\mu^{-m}}}{\boldsymbol{\mu_w}} + \boldsymbol{2.5}) \times \frac{\boldsymbol{\rho u_t}^2}{\boldsymbol{2}}$$

$$\Delta \boldsymbol{P_t} = \boldsymbol{221.08\ Pa}$$

Friction Factor (from fig 6e)	**j_f**	**0.0003**	
	ΔP	221.08	kPa

Shell Side Pressure Drop Calculation

$$\Delta \boldsymbol{P_s} = \boldsymbol{8j_f} \times \frac{\boldsymbol{D_s}}{\boldsymbol{d_e}} \times \frac{\boldsymbol{L}}{\boldsymbol{l_b}} \times \frac{\boldsymbol{\rho u_s}^2}{\boldsymbol{2}} \times \frac{\boldsymbol{\mu^{-0.14}}}{\boldsymbol{\mu_w}}$$

Baffles	**Bf**	**6**	
Pressure Drop	ΔP_S	55.18	kPa

6.1.2 Air Preheater

Service	**Boiler**
Type	Floating Head Heat Exchanger
Fluid Allocation	Tube Side = Air
	Shell Side = Flue Gases

Tube Side Water

$\boldsymbol{T_{in} = 30\ °C}$ $\boldsymbol{T_{out} = 96\ °C}$ $\boldsymbol{Massflowrate = 11018.19\ \frac{kg}{hr}}$

$$T_{avg} = 63\,°C$$

Shell Side Flue Gas

$T_{in} = 214\,°C$ $\qquad$ $T_{out} = 159\,°C$

$Massflowrate = 11850.43\,\frac{kg}{hr}$ $\qquad$ $T_{avg} = 186.5\,°C$

6.1.2.1 Properties of Shell and Tube Side Fluid

Physical Properties of Air

Physical Property	**Unit**	**Tube Side Air**
Density (ρ)	kg/m^3	1.060
Specific Heat (C_P)	kJ/kg°C	1.005
Viscosity (μ)	mNs/m^2	0.018
Thermal Conductivity (k)	W/m°C	0.0288
Assumption		
No of Passes (N_P)		2
Fouling Factor (h_d) **(from table 6 a)**	$W/m^2.°C$	6,000

Physical Properties of Flue gas

Physical Property	**Unit**	**Flue Gas**
Density (ρ)	kg/m^3	0.68
Specific Heat (C_P)	kJ/kg°C	1.15
Viscosity (μ)	mNs/m2	0.029
Thermal Conductivity (k)	W/m°C	0.0389

Assumption		
No of Passes (N_P)		1
Fouling Factor (h_d) (from table 6 a)	W/m^2°C	4,000

We assume our heat transfer coefficient $U = 40\frac{W}{m^2C}$ (from table 6 b)

LMTD

$$LMTD = \frac{\Delta T_2 - \Delta T_1}{\ln(\frac{\Delta T_2}{\Delta T_1})}$$

$$\Delta T_1 = 214 - 96 = 118°C$$

$$\Delta T_2 = 156 - 30 = 126°C$$

$$LMTD = 121.95°C$$

Corrected LMTD

$$R = \frac{T_1 - T_2}{t_2 - t_1}$$

$$R = 0.87$$

$$S = \frac{t_2 - t_1}{T_2 - t_1}$$

$$S = 0.52$$

$$\Delta T_m = F_t\, \Delta Tl_m$$

$$\Delta T_m = 102.7\ °C$$

Where Ft is found from equation:

$$F_t = \frac{\sqrt{(R^2+1)}\ln\left[\frac{(1-S)}{(1-RS)}\right]}{(R-1)\ln\left[\frac{2-S[R+1-\sqrt{(R^2+1)}]}{2-S[R+1+\sqrt{(R^2+1)}]}\right]}$$

Heat Duty and Heat transfer Area:

$$Q = mCp\Delta T$$

$$A = \frac{Q}{U\Delta Tlm}$$

	Units	Tube	Shell
Flow rate (m)	kg/h	11018.19	11850.43
Heat Duty (Q)	kW	203.01	219.56

$$A = 49.41m^2$$

6.1.2.2 Tube Size and Tube Layout

Material of Construction of Tube: Carbon Steel

$$d_O = 25mm$$

$$P_t = triangular\ pitch$$

$$L = 3.50\ m$$

$$BWG = 16$$

$$d_i = 20mm$$

Calculations

Tube Pitch (P_t)	**31.25**	mm
Area of one tube (A_1)	0.2747	m^2
No of tubes (N_t)	180	
Tube/pass (N_P)	90	
Tube cross sectional area (A_C)	490.63	mm^2
Area per pass	0.102457	m^2
Air Linear Velocity (u_t)	201.7	m/s
Tube side coefficient (h_i)	1289.11	$W/m^{2}°C$

$$\boldsymbol{Tube\ Pitch = 1.25 d_O}$$

$$\boldsymbol{A = \pi d L}$$

$$\boldsymbol{Ac = \frac{\pi d^2}{4}}$$

$$\boldsymbol{Re = \frac{p \times d_i \times u_t}{\mu}}$$

$$\boldsymbol{h_i = \frac{4200(1.35 + 0.02t){u_t}^{0.8}}{{d_i}^{0.2}}}$$

6.1.2.3 Bundle and Shell Diameter

Assumptions

$$\boldsymbol{K_1 = 0.249}$$

$$\boldsymbol{n_1 = 2.207}$$

(From table 6 c)

Bundle Diameter Clearance (mm) (from fig 6 c)	**BDC**	**58**
Baffle Cut		25%
Heat Transfer Factor (from fig 6 f)	j_h	0.002

Calculations

$$\boldsymbol{D_b = d_o (\frac{N_t}{K_1})^{1/n_1}}$$

Hence Bundle Diameter = **395mm**

$$\boldsymbol{D_s = BDC + D_b}$$

Shell Diameter is therefore **453 mm**

$$\boldsymbol{Baffle\ Spacing = 0.2 \times D_s}$$

Hence Baffle Spacing (l_b) is **90.6mm**

To calculate Shell Area

$$A_s = \frac{(p_t - d_o)D_s \times l_b}{p_t}$$

$$A_s = 8208.36\ mm$$

Equivalent Diameter (mm)	**D_e**	**22.19**
Mass Velocity	G_s	401.02
Flow rate (kg/hr)	V_s	11850.43
Renoyld Number	Re	324110
Thermal Conductivity (W/m°C)	K_f	0.03992
Prandtl Number	Pr	0.9
Shell Side Coefficient (W/m²°C)	H_s	1249

For an equilateral triangle pitch arrangement

$$d_e = \frac{4(\frac{p_t}{2} \times 0.87p_t - \frac{1}{2}\pi \frac{d_O{}^2}{4})}{\pi d_o}$$

$$us = \frac{G_s}{\rho}$$

$$h_o = \frac{k_f}{d_i} \times j_h Re \quad Pr^{0.33}$$

6.1.2.4 Overall Heat Transfer Coefficient

$$\frac{1}{U_o} = \frac{1}{h_o} + \frac{1}{h_{od}} + \frac{d_o \ln(\frac{d_o}{d_i})}{h_o} + \frac{d_o}{d_i} \times \frac{1}{h_{id}} + \frac{d_o}{d_i} \times \frac{1}{h_i}$$

$$\frac{1}{U} = 0.00259$$

$$U = 386\ \mathrm{W/m^2{}^\circ C}$$

6.1.2.5 Pressure Drop

Tube Side Pressure Drop Calculation

$$\Delta \boldsymbol{P_t} = \boldsymbol{N_p}(\boldsymbol{8j_f} \times \frac{\boldsymbol{L}}{\boldsymbol{d_i}} \times \frac{\boldsymbol{\mu^{-m}}}{\boldsymbol{\mu_w}} + \boldsymbol{2.5}) \times \frac{\boldsymbol{\rho u_t}^2}{\boldsymbol{2}}$$

$$\Delta \boldsymbol{P_t} = \boldsymbol{38\ kPa}$$

Where, $j_f = 0.00041$

Shell Side Pressure Drop Calculation

$$\Delta \boldsymbol{P_s} = \boldsymbol{8j_f} \times \frac{\boldsymbol{D_s}}{\boldsymbol{d_e}} \times \frac{\boldsymbol{L}}{\boldsymbol{l_b}} \times \frac{\boldsymbol{\rho u_s}^2}{\boldsymbol{2}} \times \frac{\boldsymbol{\mu^{-0.14}}}{\boldsymbol{\mu_w}}$$

$$\Delta \boldsymbol{P_t} = \boldsymbol{62\ kPa}$$

Where, $J_f = 0.00068$

6.1.3 Condensing Economizer:

Service	**Condensing Economizer**
Type	Floating Head Heat Exchanger
Fluid Allocation	Tube Side = Water
	Shell Side = Flue Gases

Tube Side Water

$\boldsymbol{T_{in} = 25\ °C}$ $\boldsymbol{T_{out} = 84°C}$ $\boldsymbol{Massflowrate = 3573\frac{kg}{hr}}$ $\boldsymbol{T_{avg} = 54.5\ °C}$

Shell Side Flue Gas

$\boldsymbol{T_{in} = 159\ °C}$ $\boldsymbol{T_{out} = 91\ °C}$ $\boldsymbol{Massflowrate = 11850.43\frac{kg}{hr}}$

$\boldsymbol{T_{avg} = 125\ °C}$

6.1.3.1 Properties of Shell and Tube Side Fluid
Physical Properties of Water

Physical Property	Unit	Tube Side Water
Density (ρ)	kg/m^3	985.00
Specific Heat (C_P)	kJ/kg°C	4.200
Viscosity (μ)	mNs/m^2	0.800
Thermal Conductivity (k)	W/m°C	0.59
Assumption		
No of Passes (N_P)		2
Fouling Factor (h_d) **(from table 6 a)**	$W/m^2°C$	3,000

Physical Properties of Flue gas

Physical Property	Unit	Flue Gas
Density (ρ)	kg/m^3	0.68
Specific Heat (C_P)	kJ/kg°C	1.1
Viscosity (μ)	mNs/m^2	0.025
Thermal Conductivity (k)	W/m°C	0.0377
Assumption		
No of Passes (N_P)		1
Fouling Factor (h_d) **(from table 6 a)**	$W/m^2°C$	4,000

We assume our heat transfer coefficient $\boldsymbol{U = 150\,\frac{W}{m^2C}}$ (from table 6 b)

LMTD

$$\boldsymbol{LMTD = \frac{\Delta T_2 - \Delta T_1}{\ln(\frac{\Delta T2}{\Delta T1})}}$$

$$\boldsymbol{\Delta T_1 = 159 - 84 = 75°C}$$

$$\boldsymbol{\Delta T_2 = 91 - 30 = 61°C}$$

$$\boldsymbol{LMTD = 67.76°C}$$

Corrected LMTD

$$\boldsymbol{R = \frac{T_1 - T_2}{t_2 - t_1}}$$

$$\boldsymbol{R = 1.26}$$

$$\boldsymbol{S = \frac{t_2 - t_1}{T_1 - t_2}}$$

$$\boldsymbol{S = 0.62}$$

$$\boldsymbol{\Delta Tm = Ft\,\Delta Tlm}$$

$$\boldsymbol{\Delta Tm = 60.31\ C}$$

Where Ft is found from equation:

$$F_t = \frac{\sqrt{(R^2+1)}\ln\left[\frac{(1-S)}{(1-RS)}\right]}{(R-1)\ln\left[\frac{2-S[R+1-\sqrt{(R^2+1)}]}{2-S[R+1+\sqrt{(R^2+1)}]}\right]}$$

6.1.3.2 Heat Duty and Heat transfer Area:

$$\boldsymbol{Q = mC_P\Delta T}$$

$$\boldsymbol{A = \frac{Q}{U\Delta Tl_m}}$$

	Units	Tube	Shell
Flow rate (m)	kg/h	3573	11850.34
Heat Duty (Q)	kW	225.09	246.23

$$\boldsymbol{A = 27.21m^2}$$

6.1.3.3 Tube Size and Tube Layout

Material of Construction of Tube: Carbon Steel

$$\boldsymbol{do = 25mm}$$

$$\boldsymbol{P_t = triangular\ pitch}$$

$$\boldsymbol{L = 3.5\ m}$$

$$\boldsymbol{BWG = 16}$$

$$\boldsymbol{d_i = 20mm}$$

$\boldsymbol{Heat\ Transfer\ Factor = 0.003}$ (From figure 6 b)

Calculations

Tube Pitch (P_t)	**31.250**	
Area of one tube (A_1)	274.75	mm^2
No of tubes (N_t)	100	
Tube/pass (N_P)	50	
Tube cross sectional area (A_C)	314.00	mm^2
Area per pass	0.0157	m^2
Water mass velocity (V_t)	66.40	kg/sm^2
Water Linear Velocity (u_t)	0.06	m/s
Tube side coefficient (h_i)	980	$W/m^2°C$

$$Tube\ Pitch = 1.25do$$

$$A = \pi dL$$

$$A_C = \frac{\pi}{4d^2}$$

$$Re = \frac{p \times di \times u_t}{\mu}$$

$$h_i = \frac{4200(1.35 + 0.02t)ut^{0.8}}{di^{0.2}}$$

6.1.3.4 Bundle and Shell Diameter

Assumptions

$$K_1 = 0.249$$

$$n_1 = 2.207$$

(From table 6 c)

Bundle Dia Clearance (mm) (from fig 6 c)	**BDC**	**55**
Baffle Cut		25%
Heat Transfer Factor (from fig 6 f)	j_h	0.003

Calculations

$$D_b = d_o(\frac{N_t}{K_1})^{1/n_1}$$

Hence Bundle Diameter = 389mm

$$D_s = BDC + D_b$$

Shell Diameter is therefore 433.21 mm

$$Baffle\ Spacing = 0.2 \times D_s$$

Hence Baffle Spacing (lb) is 86mm

To calculate Shell Area

$$A_s = \frac{(p_t - d_o)D_s \times l_b}{p_t}$$

$$A_s = 7451.21\ mm^2$$

Equivalent Diameter (mm)	**D_e**	**22.19**
Mass Velocity	G_s	441.79
Flow rate (kg/hr)	V_s	11850.43
Velocity (kg/sm^2)	U_s	712.56
Renoyld Number	Re	392132
Thermal Conductivity (W/m°C)	K_w	16
Prandtl Number	Pr	0.9
Shell Side Coefficient (W/m^2°C)	H_s	8489

For an equilateral triangle pitch arrangement

$$d_e = \frac{4(\frac{p_t}{2} \times 0.87p_t - \frac{1}{2}\pi\frac{d_O{}^2}{4})}{\pi d_o}$$

$$u_s = \frac{G_s}{\rho}$$

$$h_o = \frac{k_f}{d_i} \times j_h Re \quad Pr^{0.33}$$

6.1.3.5 Overall Heat Transfer Coefficient

$$\frac{1}{U_o} = \frac{1}{h_o} + \frac{1}{h_{od}} + \frac{d_o \ln(\frac{d_o}{d_i})}{h_o} + \frac{d_o}{d_i} \times \frac{1}{h_{id}} + \frac{d_o}{d_i} \times \frac{1}{h_i}$$

Overall Heat Transfer Coefficient	**1/U**	**0.0042194**	
	U	237	W/m^2°C

6.1.3.6 Pressure Drop

Tube Side Pressure Drop Calculation

$$\Delta P_t = N_p(8j_f \times \frac{L}{d_i} \times \frac{\mu^{-m}}{\mu_w} + 2.5) \times \frac{\rho {u_t}^2}{2}$$

$$\Delta P_t = 312\ Pa$$

Shell Side Pressure Drop Calculation

$$\Delta P_s = 8j_f \times \frac{D_s}{d_e} \times \frac{L}{l_b} \times \frac{\rho {u_S}^2}{2} \times \frac{\mu^{-0.14}}{\mu_w}$$

$$\Delta P_s = 742\ Pa$$

TABLES:

Fluid	Coefficient (W/m^2°C)	Factor (resistance) (m^2°C/W)
River water	3000–12,000	0.0003–0.0001
Sea water	1000–3000	0.001–0.0003
Cooling water (towers)	3000–6000	0.0003–0.00017
Towns water (soft)	3000–5000	0.0003–0.0002
Towns water (hard)	1000–2000	0.001–0.0005
Steam condensate	1500–5000	0.00067–0.0002
Steam (oil free)	4000–10,000	0.0025–0.0001
Steam (oil traces)	2000–5000	0.0005–0.0002
Refrigerated brine	3000–5000	0.0003–0.0002
Air and industrial gases	5000–10,000	0.0002–0.0001
Flue gases	2000–5000	0.0005–0.0002
Organic vapours	5000	0.0002
Organic liquids	5000	0.0002
Light hydrocarbons	5000	0.0002
Heavy hydrocarbons	2000	0.0005
Boiling organics	2500	0.0004
Condensing organics	5000	0.0002
Heat transfer fluids	5000	0.0002
Aqueous salt solutions	3000–5000	0.0003–0.0002

Table 6 (a) Fouling factors typical values

Triangular pitch, $p_t = 1.25d_o$					
No. passes	1	2	4	6	8
K_1	0.319	0.249	0.175	0.0743	0.0365
n_1	2.142	2.207	2.285	2.499	2.675
Square pitch, $p_t = 1.25d_o$					
No. passes	1	2	4	6	8
K_1	0.215	0.156	0.158	0.0402	0.0331
n_1	2.207	2.291	2.263	2.617	2.643

Table 6 b Typical Tube Arrangements and Constants for use

Shell and tube exchangers

Hot fluid	Cold fluid	U (W/m^2°C)
Heat exchangers		
Water	Water	800–1500
Organic solvents	Organic solvents	100–300
Light oils	Light oils	100–400
Heavy oils	Heavy oils	50–300
Gases	Gases	10–50
Coolers		
Organic solvents	Water	250–750
Light oils	Water	350–900
Heavy oils	Water	60–300
Gases	Water	20–300
Organic solvents	Brine	150–500
Water	Brine	600–1200
Gases	Brine	15–250
Heaters		
Steam	Water	1500–4000
Steam	Organic solvents	500–1000
Steam	Light oils	300–900
Steam	Heavy oils	60–450
Steam	Gases	30–300
Dowtherm	Heavy oils	50–300
Dowtherm	Gases	20–200
Flue gases	Steam	30–100
Flue	Hydrocarbon vapours	30–100
Condensers		
Aqueous vapours	Water	1000–1500
Organic vapours	Water	700–1000
Organics (some non-condensables)	Water	500–700
Vacuum condensers	Water	200–500
Vaporisers		
Steam	Aqueous solutions	1000–1500
Steam	Light organics	900–1200
Steam	Heavy organics	600–900

Table 6 c Typical Overall Coefficients

FIGURES

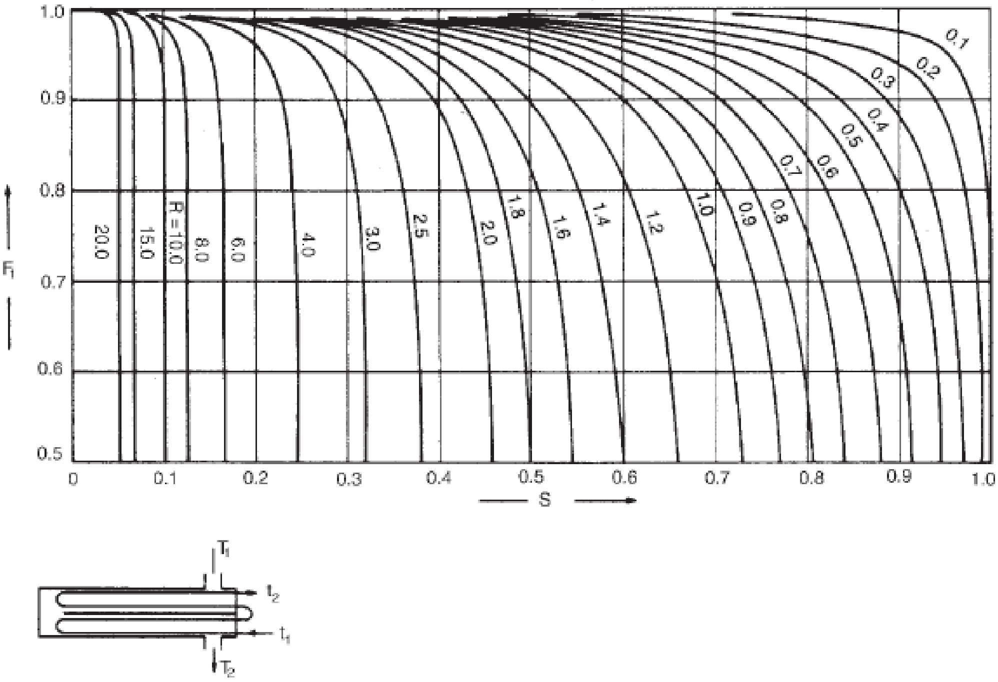


Fig 6 (a) Temperature Correction Factor: 2 shell passes; 4 or multiple of 4 tube passes

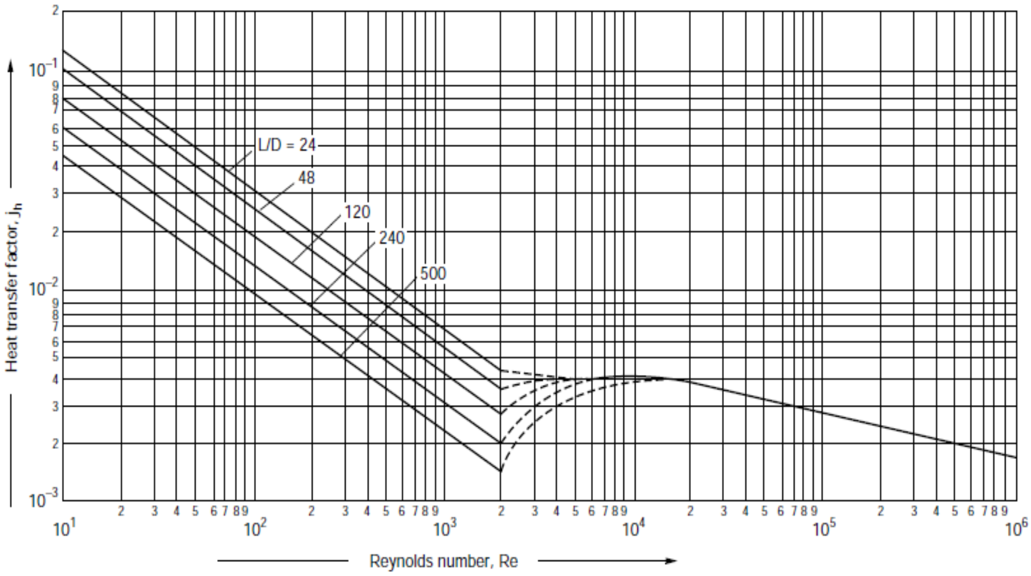


Fig 6 (b) Tube Side Heat Transfer Factor

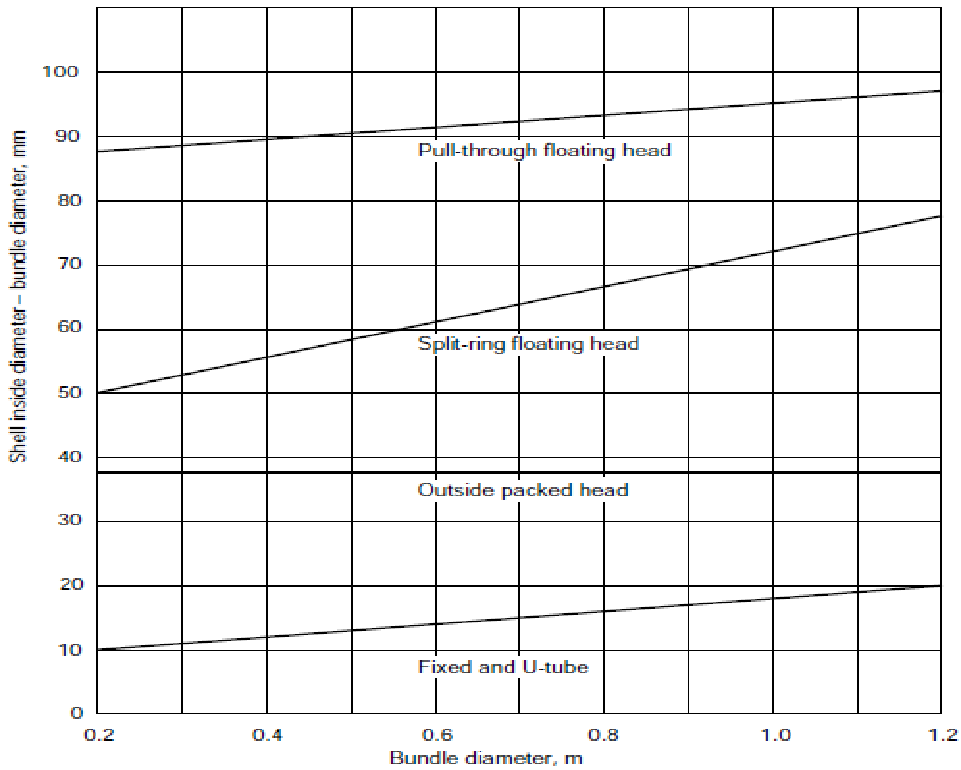


Fig 6 (c) Shell Bundle Clearance

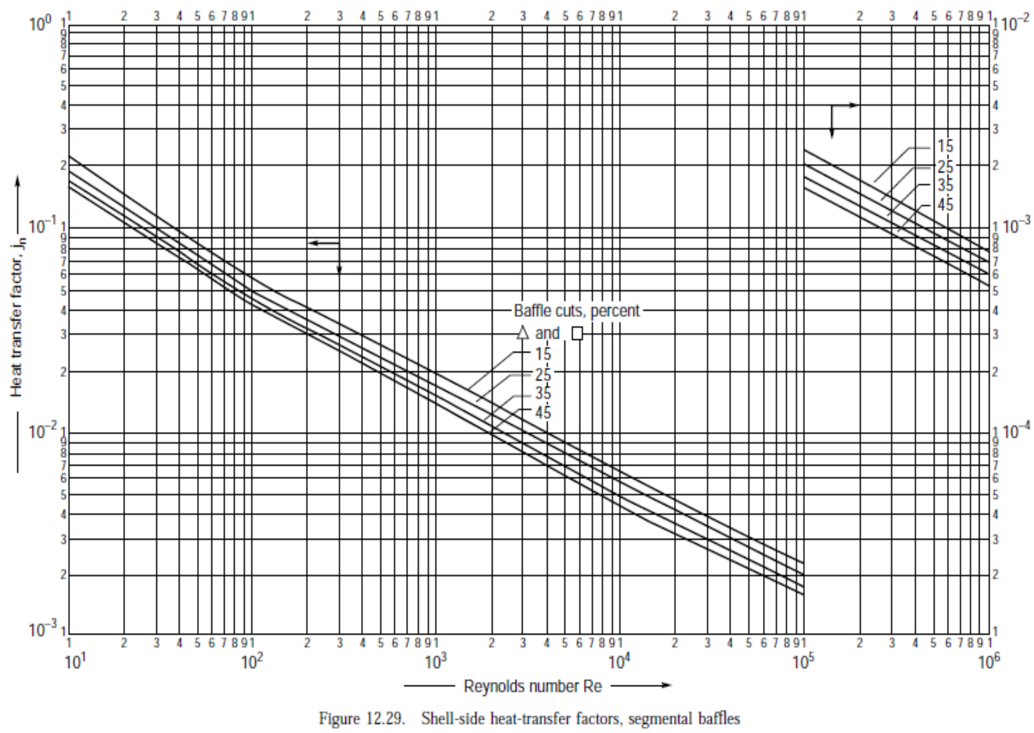


Fig 6 (d) Shell side Heat Transfer Factor

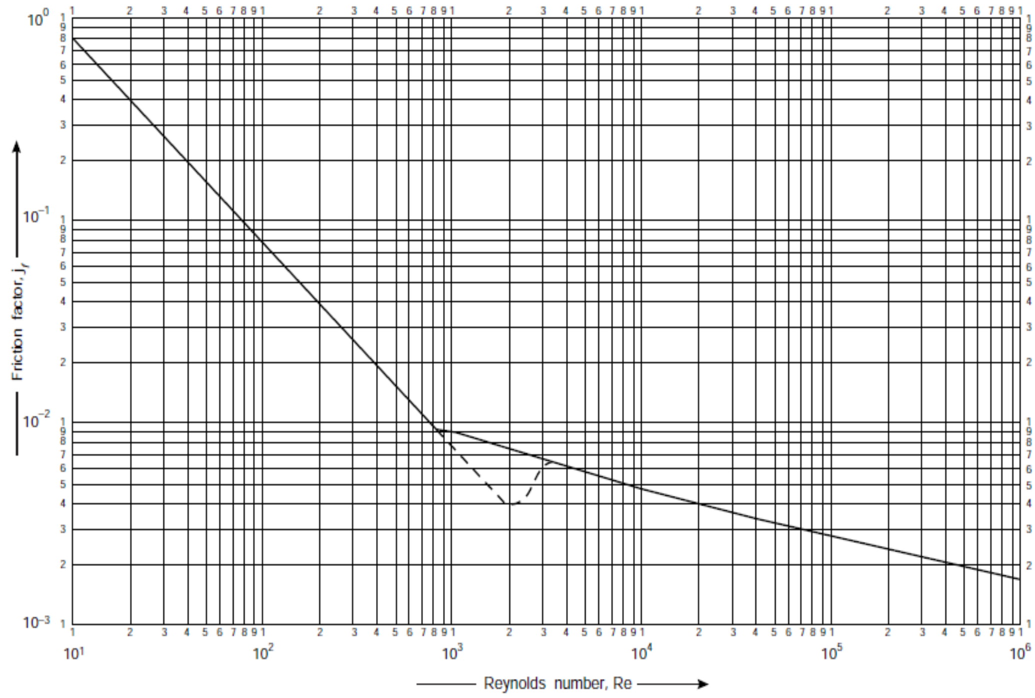


Fig 6 (e) Tube side Friction Factor

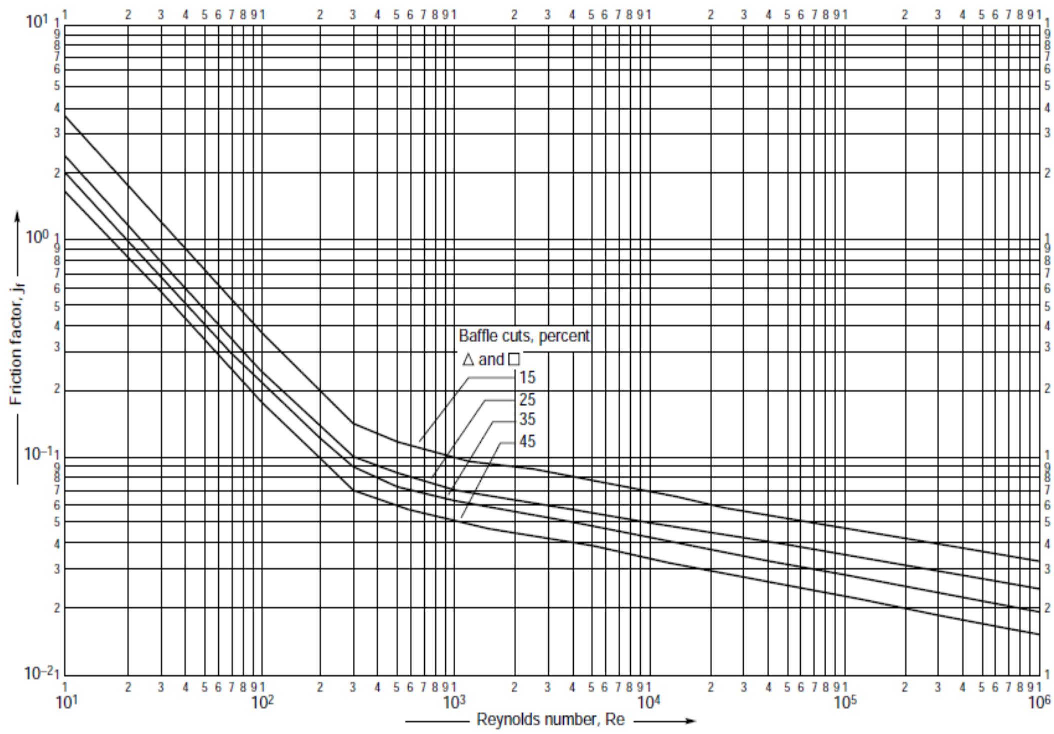


Fig 6 (f) Shell side Friction Factor

7 Economic evaluation

7.1 Condensing Economizer

Cost of Equipment

$$\boldsymbol{Area = 27.21\ m^2}$$

$$\boldsymbol{Cost = \ 26,400\$}$$

$$\boldsymbol{Purchase\ Cost = Cost\ \times Pressure\ factor}$$

$$\boldsymbol{= 26,400 \times 1.1 \times 1}$$

$$\boldsymbol{= \$\ 29,040}$$

The cost of erection, piping and instrumentation are the additional costs on equipment

Using Lang's factors to calculate the cost

$$\boldsymbol{Physical\ Cost = Purchase\ Cost\ (1 + 0.4 + 0.7 + \ 0.2 + 0.1)}$$

$$\boldsymbol{= 29,040 \times 2.4}$$

$$\boldsymbol{= \$\ 69,696}$$

Now adding the contingency and contractor's fee

$$\boldsymbol{Total\ Cost = Physical\ Cost\ \times (1 + 0.3 + 0.1 + 0.05)}$$

$$\boldsymbol{= 69,696 \times 1.45}$$

$$\boldsymbol{= \$101,059}$$

Adding the working capital now

$$\boldsymbol{Working\ Capital = 0.05 \times \$101,059}$$

$$\boldsymbol{= \$5,052}$$

$$\boldsymbol{Investment = working\ capital + Total\ Cost}$$

$$\boldsymbol{= 101,059 + 5,052}$$

$$\boldsymbol{= \$\ 106,111}$$

7.2 Air Preheater

$$\boldsymbol{Area = 49.41\ m^2}$$

$$\boldsymbol{Cost = \$\ 28,800}$$

$$\boldsymbol{Purchase\ Cost = Cost\ \times Pressure\ factor}$$
$$= \mathbf{28,800 \times 1.1 \times 1}$$
$$= \$\ \mathbf{31,680}$$

The cost of erection, piping and instrumentation are the additional costs on equipment

Using Lang's factors to calculate the cost

$$\boldsymbol{Physical\ Cost = Purchase\ Cost}\ (\mathbf{1 + 0.4 + 0.7 + 0.2 + 0.1})$$
$$= \mathbf{31,680 \times 2.4}$$
$$= \$\ \mathbf{76,032}$$

Now adding the contingency and contractor's fee

$$\boldsymbol{Total\ Cost = Physical\ Cost}\ \times (\mathbf{1 + 0.3 + 0.1 + 0.05})$$
$$= \mathbf{76,032 \times 1.45}$$
$$= \$\mathbf{110,246}$$

Adding the working capital now

$$\boldsymbol{Working\ Capital} = \mathbf{0.05 \times 87,436}$$

$$= \$\mathbf{5,512}$$

$$\boldsymbol{Investment = working\ capital + Total\ Cost}$$
$$= \mathbf{110,246 + 5,512}$$
$$= \$\ \mathbf{115,758}$$

$$\boldsymbol{Total\ Investment} = \mathbf{106,111 + 115,758}$$

$$= \$\ \mathbf{221,869}$$

7.3 Rate of Return Calculation

Fuel (kg/hr)	**Present consumption**	**Proposed consumption**	**Fuel Saving**
Natural Gas	914	828	86

$$\boldsymbol{Fuel\ saving\ per\ year = 86 \times 24\ \times 360}$$

$$\boldsymbol{= 743,040\ kg/year}$$

$$\boldsymbol{Fuel\ price\ per\ kg = \$\ 0.50}$$

$$\boldsymbol{Total\ savings\ per\ year = 743,040 \times 0.50}$$

$$\boldsymbol{= \$\ 371,520}$$

$$\boldsymbol{Payback\ Period = \frac{221869}{371520}}$$

$$\boldsymbol{= 0.59\ years}$$

$$\boldsymbol{= 7\ months\ and\ 5\ days}$$

8 Instrumentation and Process Control

8.1 Introduction

Instrumentation is a fundamental requisite to control any process system. The control can be applied automatically, semi-automatically or manually. The quality of the product depends upon the quality of control applied and it bears a relationship to the accuracy of the measurement methods which are used. The controls are basically applied on four parameters which are flow, temperature, pressure and level. Therefore, effective means of measurement is an integral part of the design and formulation of any process control system.

8.1.1 Temperature Measurement and Control

The temperature measure is applied to each equipment where there is variation of temperature due to heat transfer between the streams. The inlet and outlet temperatures of equipment such as heat exchangers, condensers, deaerator and boiler are measured to ensure the routine process is going on and there are no discrepancies due to problem in any equipment. Most of the temperature gauges are thermocouples which facilitate measurements to a centralized location. For higher accuracy of measurements, resistance thermometers are used.

8.1.2 Pressure Measurement and Control

Most of the process systems use pressurized equipment and vessel to maintain a certain environment within vessels. It is a valuable indication of what is the state and composition of the monitored stream. Different equipment including turbines, compressors and pumps and flash vessels which deal with the pressure changes of the fluid, are equipped with pressure measuring devices. It signifies the changes in energy and determines the energy held by each stream.

The pressure gauges installed in industry are either elastic element type used to have local readings as well as transmit data to the centralized control room. Other extensively used industrial pressure element is the Diaphragm or Bellow gauges.

8.1.3 Measurements and Control

Flow measurements are the most important part of the process control when it comes to determine the economic aspects of a plant. Flow indicators meters the various streams to ensure that the designed values are being achieved while processing and also to calculate different utility consumptions to calculate the utility costs and efficiencies. The flow indication is usually done using variable head devices and to some special cases where a high pressure drop is affordable, variable area devices like rotameter is also used.

8.1.4 Level Measurements and Control

Level measurements and instrumentations is an important control of the intermediate storage devices, flash vessels and storage tanks where hold up is required to process the liquid. The level is measured via two types of methods: Difference in static pressure of fluid and use of a wet able material to determine the height of the fluid. Another traditional method still applied in few tanks which are in remote areas relevant to the control rooms are measured for level via dip method. This method is usually used to calculate the amount of diesel and fuel storage tanks and is a good method in case of electrical instrumentation failure.

8.2 Types of Control Systems

A control system is the amalgamation of different control schemes applied on the process to control the outputs of the system. These variables can either be temperature, flow or pressure of the system, each controlled by manipulating the input variable of the system. There are two main classifications of the control systems.

8.2.1 Open Loop Control System

An open loop control system does not have the system’s output interlinked with the overall control of the system. In an open loop control system, the input variable is monitored and control is applied only on its basis. The disturbances are minimal as no feedback is taken from the output to maintain the system. It is a cost efficient control but the accuracy of the control and effectiveness is very low.

8.2.2 Closed Loop Control System

Closed loop control system uses the feedback from the output stream to take action on the manipulated variable to achieve a certain set point. It has same forward path as open loop system but also has multiple feedback paths to provide information for the desired changes.

The actual process variable conditions are compared with given set point to apply control on the manipulated variable using different variables. A suitable control action is determined on the basis of the error signal generated to bring the system output to the desired value. The accuracy of the closed loop control is far more than the open loop control system and it has more costly maintenance as well.

Instrumentation and process control is a necessity for safe operation of every system, likewise special consideration was given in our project to assess sensitive operations and issue controlling equipment for them. There are two basic parameters that are to be controlled for an operation and they are listed as following:

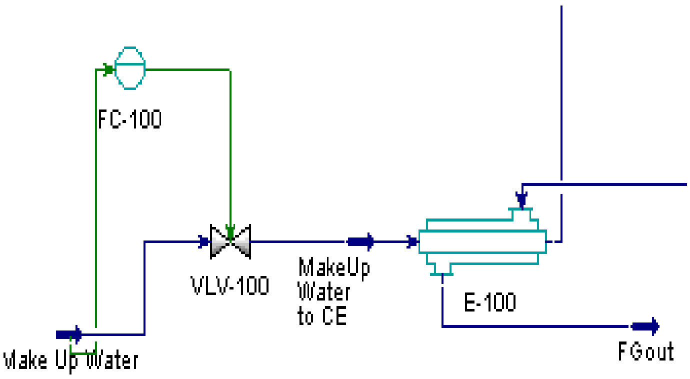
8.3 Installed Controllers

8.3.1 Make-up water flow controller

Flow is necessary to be controlled throughout the operation to increase efficiency and safety of the process. To maintain this flow, we need to control the flow by controlling the input of the overall material balance. The main input of our process is the make-up water. By controlling this flow we can consequently control the overall mass of water in the cycle and capacity of operation. A flow transmitter is placed on the make-up water stream which reads and transmits the value of flow rate at the makeup water stream and manipulates the valve opening to control the flowrate.

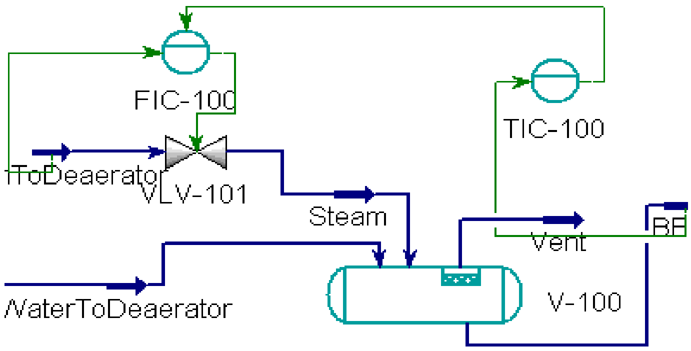
Make Up Water Flow Controller

Make Up Water Flow Controller				
Name of controller	Type of controller	Manipulated variable	Controlled Variable	Action of controller
FC	PID	Valve Opening	Make Up Water Flowrate	Direct



8.3.2 Steam Injection into the Deaerator:

Deaerator				
Name of controller	Type of controller	Manipulated variable	Controlled Variable	Action of controller
FC	PID	Valve Opening	Steam Flowrate	Direct
TC	PID	Steam Injection	Temperature	Reverse

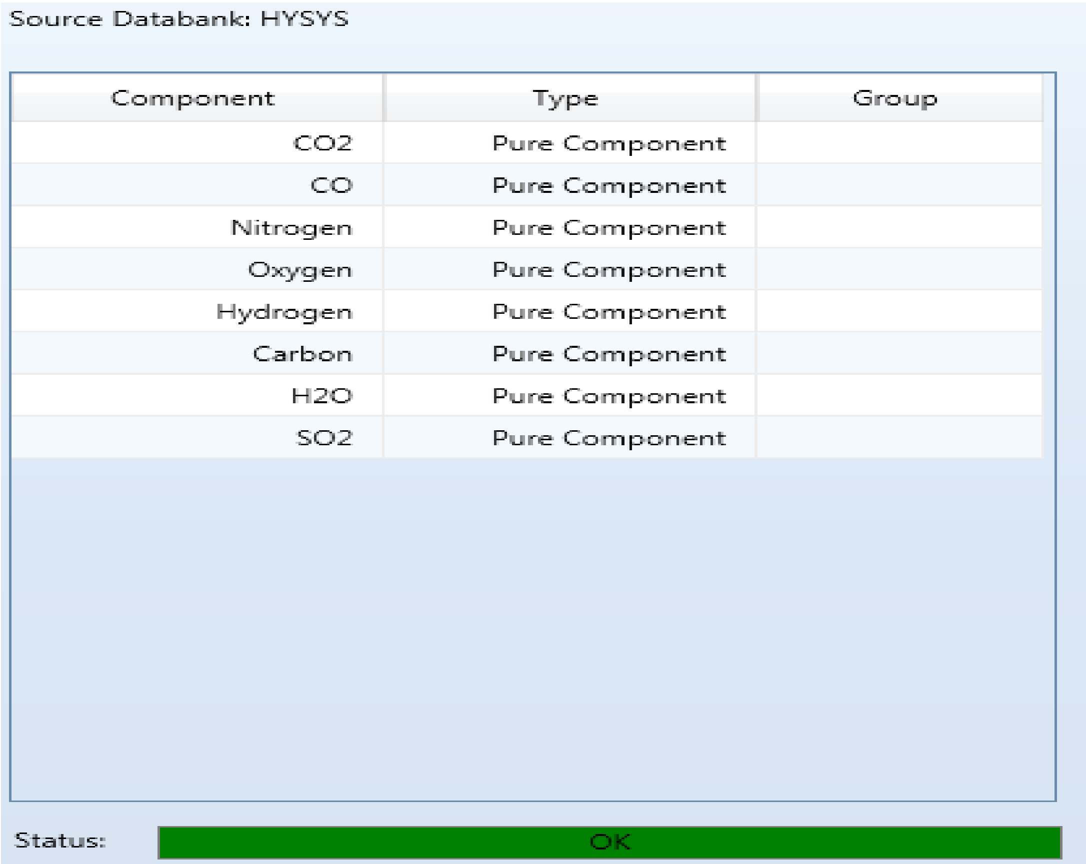


This problem addresses probably the most sensitive parameter of the operation which is the temperature. High temperatures can damage the equipment due to the high kinetic energy molecules contain in high temperature state which in turn can significantly not only damage the equipment but even pose a threat of failure to the whole operation.

To control this feature a temperature transmitter is installed on the deaerator feed stream. As the water is in a cycle throughout the operation, the temperature is required to keep to an optimum. To do this, the temperature transmitter sends output to a flow controller which controls the flow of the steam injection into the deaerator and as the deaerator additionally acts as a heat exchanger. Controlling the steam injection flow can help control the heat exchange and hence temperature of the water in the cycle.

9 Simulation on ASPEN Hysys

The simulation on Aspen Hysys was done to verify material and energy balance calculations along with design parameters. Owing to the complexity of the feed, the system was kept in steady state only.
The components were selected as follows:


Source Databank: HYSYS

Component	Type	Group
CO2	Pure Component	
CO	Pure Component	
Nitrogen	Pure Component	
Oxygen	Pure Component	
Hydrogen	Pure Component	
Carbon	Pure Component	
H2O	Pure Component	
SO2	Pure Component	

Status: OK

Fig 9 a Component List

Peng Robinson was selected as the property package

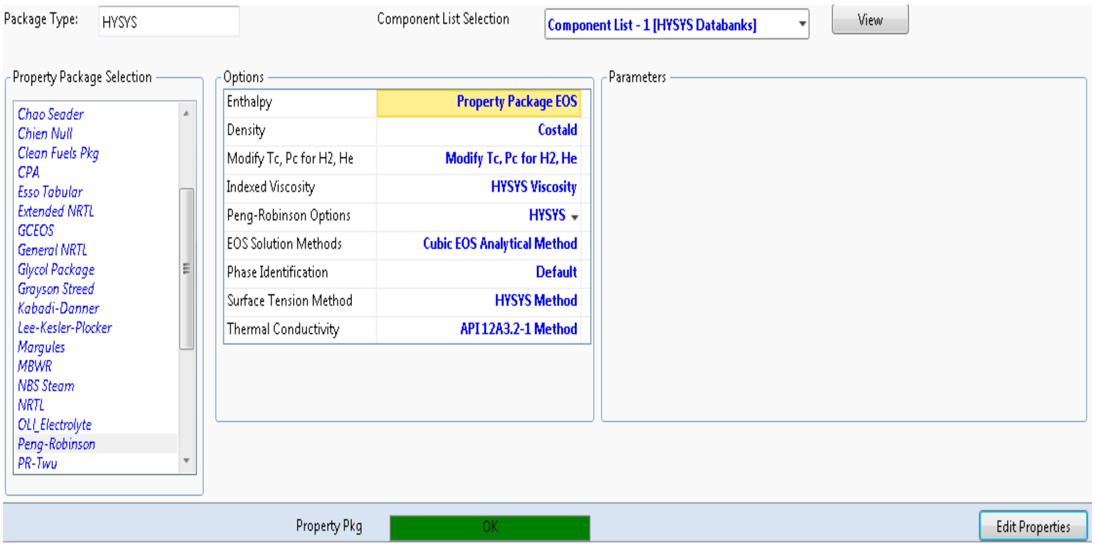


Fig 9 b Property Package

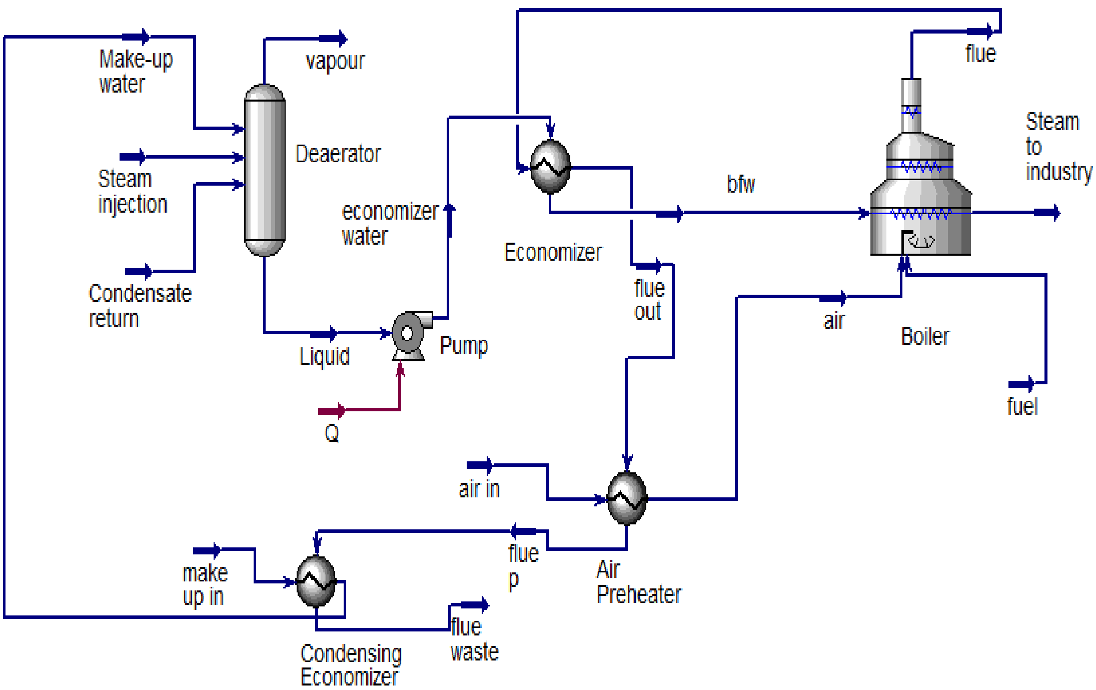


Fig 9 c Aspen Hysys Flow Diagram

10. HAZOP Study

Health and safety are the essential features of an industry. The government legalities and the health and safety regulations force employers to provide proper health and safety environment to the employees. The health and safety is greatly affected by the hazards that might be present at the workplace. Anything which has the ability to cause the damage is treated as hazard. A hazard is basically a threat which can have the power to cause, financial, physical or chemical damage to a work environment. A strong and vigilant policy needs to be in place in order to overcome this problem of health and safety.

There are many regulations in place for as different health and safety measures. These regulations are implemented in order to enforce the measures that are necessary in a working environment. There could be a variety of hazards and they need to be solved and taken care of, categorically. A detailed HAZOP study can be performed on a specific plant or system to identify the possible hazards and their intensity. The level of risk and the ability of damage for a particular hazard can be evaluated successfully.

The HAZOP Study basically comprises of the following evaluations.

1. Identification of the possible hazards
2. Measures to control for the possible hazards
3. Improvising the process
4. Minimizing the loss due to liability

10.1 Procedure for HAZOP Study

The HAZOP study holds its importance in the industry. There is however a brief and elaborative way of performing the HAZOP study. The following steps can be taken in order to successfully evaluate the HAZOP study.

- Division of the system into different sections
- Choosing the basis as study notes
- Depicting the intention of the section
- Selecting the involved parameters

- Applying the guide word
- Determination of causes of deviation
- Evaluating the consequences
- Recommendations
- Recording the information

10.1.1 Deaerator

Guide word	Deviation	Cause	Consequence	Safeguard
More	Temperature	Higher flow of steam	Might damage insulation Overheating of column	Temperature regulation and control.
Low	Temperature	Low pressure steam. Leakage of steam	Inefficient removal of oxygen	Temperature regulation and control.
Low	Flow	Pump blockage Major leak in pipeline	Overheating of column	Flow control and regulation
More	Flow	Problems with upstream control valves	Accumulation of water in deaerator	Flow control and regulation
Low	Pressure	Upstream pressure variations	Saturation temperature decline	Pressure regulation and control

		Upstream leakage		
More	Pressure	Upstream Pressure variation	Saturation temperature elevation More load on deaerator	Pressure regulation and control

10.1.2 Boiler

Guide Word	**Deviation**	**Cause**	**Consequences**	**Safeguard**
More	Pressure	Upstream pressure variations.	Boiling point elevation.	Pressure regulation and control.
Low	Pressure	Leakages upstream or within the boiler. Upstream pressure variations.	Less steam generated	Pressure regulation and control.
More	Temperature	High flow rate of Exhaust gases Upstream process deviations.	High volumes of steam generated. Higher steam temperature. Damage to pipes and tubes from high temperature	Temperature regulation and control.

Low	Temperature	Low flow rate of exhaust gases Upstream process deviations. Leakage.	Poor steam generation. Lower steam temperature.	Temperature regulation and control.
More	Flow	Problems with Boiler feed water pump. Problems with upstream control valves.	More load on boiler tubes. More need for steam. Accumulation of water in boiler	Flow regulation and control.

10.1.3 Air Preheater

Guide word	Deviation	Cause	Consequence	Safeguard
More	Pressure at shell side	Blockage in the outlet of exchanger	Over pressurization	Pressure regulation and control
More	Tube side pressure	Tube rupture	Mixing of air with flue gas. Increased flow rates.	Pressure regulation and control

Less	Shell side temperature	Energy losses in economizer	Condensation of flue gases	Temperature regulation and control
More	Flow	Control valve failure	More load on air preheater Condensation of flue gases	Flow regulation and control

10.1.4 Condensing Economizer

Guide word	Deviation	Cause	Consequence	Safeguard
More	Temperature	Boiler Economizer failure Fouling in boiler or economizer tubes	Higher temperature of make-up water damage to insulation more water vapor condensed	Temperature regulation and control
Low	Temperature	Improper insulation	Less water vapor condensed Lower temperature	Temperature regulation and control

		Faulty instrumentation and control	of make-up water	
Low	flow	Pump blockage Major leak in pipeline	Inefficient heating of make-up water	Flow regulation and control
More	Flow	Control valve failure	More load on economizer tubes	Flow regulation and control
Low	Pressure	Leakages upstream or within the condensing economizer. Upstream pressure variations	Less water vapor condensed	Pressure regulation and control
More	Pressure	Upstream pressure variations. .	More water vapor condensed	Pressure regulation and control

10.1.5 Boiler Feed Water Pump

Guide Word	**Process Parameter**	**Cause**	**Consequences**	**Safeguard**
More	Pressure	Increased pressure of deaerator	Pump damage. Recirculation or backflow.	Flow regulation and control.
Low		Decreased pressure of deaerator	More pump power. Cavitation in pump.	Flow regulation and control.
More	Flow	Increased output from deaerator Increased level of deaerator	Decrease in pump head. Reduced pump efficiency. Increased NPSH.	Flow regulation and control.
Low		Decreased level of deaerator Decreased output from deaerator.	Reduced pump efficiency. Chances of cavitation. Chances of recirculation.	Flow regulation and control.

11 Conclusions

In this investigation a boiler assembly is proposed that utilizers an air pre- heater followed by a condensing economizer to improve the efficiency of fire tube boiler. Air preheater consumes the energy of stack flue gases to preheat the combustion air to 96^{o}C. This preheated combustion air increases the efficiency of boiler by 3%. In addition, excess air was reduced to 10% which further optimized the system, thus improving the overall boiler efficiency to 80%. In condensing economizer, make up water was heated to 84^{o}C using the heat energy of stack flue gases. Utilizing the preheated make up water in the system has reduced the fuel consumption by 10%. Thus, installing air preheated coupled with condensing economizer can increase the boilers efficiency at reduce fuel consumption by extracting most of the energy from stack flue gases.

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