

INVESTIGATION OF MINI STEAM POWER PLANT PERFORMANCE AND EMISSIONS

By

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.



MOHD SALMAN BIN FATAHAL KARIM

CERTIFICATION OF APPROVAL

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ABSTRACT

Steam power plant had been commonly used as an alternative to produce electric power. Steam is the most common working fluid used in vapor power cycles because of its desirable characteristics, such as low cost, availability and high enthalpy of vaporization.

Since new Mini Steam Power Plant had been installed in Universiti Teknologi PETRONAS (UTP) Power Generation Lab, the objective of this project is to carry out further research to investigate the performance and emissions characteristics of the plant. A test guide lines need to be prepared and tested properly before this steam power plant system could be used as part of the Mechanical Engineering (ME) Thermodynamics course. But due to problem occurred to the equipment, the objective of the project had changed to study the experiments that can be conducted using the equipment.

The scope of study will be covered the literature review on boiler terminology and principles, boiler from thermodynamics point of view and all the calculations involved in the experiments.

The results obtained based from the study and research carry out through out the semester will be discussed in results and discussion section. The result will show the experiments calculations and review based from data available. Basically, there are 3 experiments taking under consideration that are steam flow measuring system, separating and throttling calorimeter and additional boiler instrumentation.

Base from the results obtained, the conclusion had been made and the recommendations from the author are also included to end up this report.

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CHAPTER 1

INTRODUCTION

1. Background of Project

Steam power plant has been widely used as an alternative to power generation source which produce most of the electric power in the world today. Steam power plants are commonly referred to as coal plants, nuclear plants or natural gas plants, depending on the type of fuel used to supply heat to the steam. But the steam goes through the same basic cycle in all of them. Therefore, all can be analyzed in the same manner.

Steam is a dry, clear and tasteless gas and more industries are using steam in their processes. Steam is the most common working fluid used in vapor power cycles because of its desirable characteristics, such as low cost, availability and high enthalpy of vaporization. Other working fluids used include sodium, potassium and mercury for high-temperature applications and some organic fluids such as benzene and freons for low temperature applications.

The devices or systems used to produce a net power output are often called engines, and the thermodynamic cycles the engines operate on are called power cycles. Heat engines are designed for the purpose of converting other forms of energy such as heat energy to work. The performance of this engine is expressed in terms of the thermal efficiency, η_{th} , which is the ratio of the net work produced by the engine to the total heat input.

2. Problem Statement

The new steam power plant system received recently need to be tested and explored its performance and emission characteristics to enable Universiti Teknologi Petronas (UTP) using it for student purposes. A test guide lines need to be prepared and tested properly before this steam power plant system could be used as part of the Mechanical Engineering (ME) Thermodynamics course.

3. Objectives and Scope of Study

3.1 Objectives of the Study

Generally, the objectives of the study can be divided into 2 main sections:

- i. To investigate the performance and emissions characteristics of the new mini steam power plant in UTP Power Generation Lab.
- ii. To prepare the manuals and guidelines for experimental work purposes as part of the Mechanical Engineering (ME) Thermodynamics course.

3.2 Scope of Study

The project is in the form of laboratory experiments using steam power plant system in UTP Power Generation Lab. Before the operation of the steam power plant begins, further study on boiler and its terminology has to be carry out. The appropriate methodology in conducting the steam power plant has to be determined first. The test conducted will be included engine performance, emissions and particulate matter by varying test conditions such as temperature, pressure and flow rate of boiler feed water.

CHAPTER 2

LITERATURE REVIEW/THEORY

A steam generator generates steam at the desired rate at the desired pressure and temperature by burning fuel in its furnace. A steam generator is a complex integration of furnace, superheater, reheater, boiler or evaporator, economizer and air preheater along with various precipitators, ash handling equipment and chimney or stack.

The boiler is that part of the steam generator where phase change occurs from liquid (water) to vapour (steam), essentially at constant pressure and temperature. However, the term “boiler” is traditionally used to mean the whole steam generator.

2.1 Classification of Boilers

The classification of boiler can be made in many different ways:

2.1.1 Usage of boiler:

a) Utility boiler

Those used by utilities for electric-power generating plant. Depending on whether the pressure of steam is below or above critical pressure (221.2 bar), they can be either subcritical or supercritical units. The subcritical boilers are water tube-drum type and usually operate at between 130 and 180 bar steam pressure. The supercritical boilers are drumless once-through type and operate at 240 bar pressure or higher. Majority of the utility boiler are of the 170-180 bar water-tube drum variety, which produced superheated steam at about 540-560 °C with one or two stages of reheating.

b) Industrial boiler

Those used in process industries like sugar, paper, jute and so on, and institutions like hospitals, commercial and residential building complexes. The boiler is smaller in size. The boiler can be pulverized coal fired, fluidized bed or stoker fired units, with coal mostly as the fuel. The boiler

can also be heat recovery types which use waste heat from various industrial processes, and are termed waste heat boilers. The boiler operates at pressure ranging from 5 to 105 bar with steam capacities up to 125 kg/s. Normally, the boiler do not produce superheated steam. It only supplied wet or saturated steam and sometimes even only hot water.

2.1.2 Classification by pressure

a) Low pressure (LP) boiler

Usually operate at 150 psi and below with critical temperature of 250 °C.

b) High pressure (HP) boiler

Boiler with operating pressure that higher than 150 psi is consider as high pressure boiler.

2.1.3 Classification by material used

The boiler can also be classify base from the material used to construct the boiler. Normally, cast iron is widely used in boiler construction, but since the revolution and development of boiler, there are several special metals that being used to construct the boiler. Reliability and cost are behind the reasons that lead to the used of the special metals that had been recognized.

2.1.4 Classification by size of boiler heating surface

Another way to classify a boiler is by the heating surface. This method is normally used by Department of Occupational Safety and Health (DOSH). This is the total area on the fireside of the boiler that is exposed to the products of combustion. This area is usually calculated on the basis of areas on the following boiler element surfaces: tubes, fire boxes shells, tube sheets and projected area of headers.

2.1.5 Classification by type of tube

a) Fire tube boiler

Fire tube boiler means that the hot gases flow through inside the tubes which are immersed in the shell containing water. As the hot gases flow through the tubes, heat is transferred from gas to water all along the length. The gas is cooled and the water is heated till there is nucleate boiling around the tubes and steam is formed. For small steam requirement, fire tube boilers are suitable.

b) Water tube boiler

The water tube boiler, where water flows through the tubes and flue gases flow outside it, puts the pressure in the tubes and the relatively small diameter drums, which are capable of withstanding extreme pressures of the boiler.

2.1.6 Classification by source of heat

The boiler can also be classified by the source of heat used for heating the boiler.

a) Electricity

There are two types of electric boiler:

- i. Units with heating elements constantly submerged in water.
- ii. Units with electrical electrodes located in a central generating chamber.

The water level recedes as the demand for steam decreases. Thus at no load, the electrodes are entirely out of water and there is no electrical consumption.

b) Fuel consumption

Fuels such as natural gas and fuel oil are used as source of heat for bigger boilers compared to the boilers that use electricity as heating element.

2.1.7 Classification by type of fuel

a) Fuel oil

Liquid fuels such as petroleum are easy to handle, easy to store and easy to burn. It has nearly constant heating values. Petroleum is primarily a mixture of hydrocarbon compounds, which may also contain nitrogen, oxygen and sulphur. The bulk of hydrocarbons belong to paraffin series, C_nH_{2n+2} , like methane (CH_4) and ethane (C_2H_6) which are gaseous and pentane (C_5H_{12}) and octane (C_8H_{18}) which are liquid.

b) Natural and petroleum gas

In some fields, the natural gas is flared or burned at wellhead because of lack of facilities to transport the gas. Since the major constituent of all natural gases is methane (critical temperature $-83\text{ }^\circ\text{C}$), cryogenic temperatures are required to maintain the gas as a liquid at moderate pressures (e.g. $-100\text{ }^\circ\text{C}$ at 36 bar). Liquid natural gas (LNG) is transported by special tankers and stored in spherical pressure vessels to be used. Compressed natural gas (CNG) is now being considered as the alternative fuel for automobiles. Liquid petroleum gas (LPG) refers to hydrocarbons such as propane, propylene, butane and so on which are liquefied under moderate pressures and at normal temperatures. It is used widely as domestic fuel and also to supplement natural gas flow.

c) Industrial waste and byproducts

Industrial wastes like blast furnace gas, coke oven gas, refinery gas, sugar factory refuse (bagasse), saw mill wood dust, rice husk and so on are also used as boiler fuels, often to boost one of the primary fossil fuels. When more than one type of fuel is simultaneously burned to meet the total heating requirement, the boiler is said to have combination firing.

2.1.8 Classification by type of working fluid

a) Water

Steam is the most common working fluid used in boilers because of its desirable characteristics, such as low cost, availability and high enthalpy of vaporization.

b) Other

Other working fluids used include sodium, potassium and mercury for high-temperature applications and some organic fluids such as benzene and freons for low temperature applications.

2.1.9 Classification by type of furnace

a) Externally fired

Externally fired fire tube boiler is which the furnace is outside the boiler shell. Coal entered manually by shovels on to the grate by opening the fire door. The products of combustion flow through the tubes which are immersed in the shell containing water. (Refer to **APPENDIX 2.1** for diagram)

b) Internally fired

The furnace is within the cylindrical shell. Combustion occurs in a horizontal corrugated flue and the combustion gases flow through the tubes in two passes until the gases are let out through chimney to atmosphere. (Refer to **APPENDIX 2.2** for diagram)

2.1.10 Classification by type of circulation

a) Natural circulation

The flow of water and steam within the boiler circuit is called circulation. Adequate circulation must be provided to carry away the heat from furnace.

If circulation is caused by density difference, the boiler is said to have natural circulation. (Refer to **APPENDIX 2.3** for diagram)

b) Force circulation

The boiler is said to have force or controlled circulation if it is caused by a pump. If the pressure of steam exceeds 180 bar, the natural circulation can not be relied upon since the density difference becomes so small. Thus, forced circulation is used where a pump circulates saturated water through all risers around furnace walls. (Refer to **APPENDIX 2.4** for diagram)

2.2 Type of Boilers

2.2.1 Fire tube boiler

The products of combustion of this type of boiler pass through its tubes or flues, which are surrounded by water. The fire tubes boilers have certain inherent advantages such as low first cost, reliability in operation, need of only unskilled labor and quick response to load changes. The fire tubes may be orientated vertically or horizontally. They may also have baffles arranged to force the products of combustion to pass through banks of tube in the water space. That arrangement increases the efficiency of the boiler because it extracts more heat from the hot gases and reduces the temperature of the gases discharged to the atmosphere through the stack.

Fire tube boilers can be classify into two types, that is externally fired or internally fired. Among the examples of internally fired of boilers are locomotive type boiler, Lancashire boilers and horizontal return tubular (HRT) boiler. The examples of externally fired of boilers are Scotch-marine boilers and package boilers.

Fire tube boilers are quite adaptable to package. The package type boiler has certain advantages:

- It is highly compact. A large surface area of heat transfer is provided in a small volume. The furnace volume is less since it is pressurized.
- No induced draught fan is required. A short chimney is provided just for disposal of flue gases.
- The entire unit is mostly fabricated in the factory itself. It is transported to the site and installed there with relative ease and fitted with all required controls, safety devices and essential fittings.
- It occupies less space.
- It is easy to operate.

Because of these advantages, package boilers were favored in process industries. The fire tube boilers have large water storage capacity and can thus meet relatively large and sudden load demands with only small pressure changes. Reduction in pressure leaves the stored water superheated and causes part of it to flash into steam. However, the large water storage increases the explosion hazard of the unit and also because of it, a longer period of time is required to bring the unit to steaming from cold condition.

The major shortcoming of a fire tube boiler is that definite size and pressure limitations are inherent in its basic design. It means that the maximum size of the unit and maximum operating pressure are limited. The tensile stress on the drum wall is a function of the drum diameter and the internal pressure given by

$$\sigma = pd / 2t$$

where σ = tensile stress, N/m²

p = gauge pressure, N/m²

d = internal diameter of the shell, m

t = thickness of wall, m

The growing needs for increased quantities of steam at higher and higher pressures could not be met by fire tube boilers. The maximum allowable working pressure for fire tube boilers are 250 psi. Base from the equation above, it show higher pressures and

larger sizes mean larger wall thicknesses. Thus, high pressures and large diameters lead to prohibitively thick shells and the thicker the shell, the higher the cost.

2.2.2 Water tube boiler

Water tube boiler is one in which the water and steam are inside the tubes and the products of combustion surround the tubes. Water tube was developed to permit increases in boiler pressure and capacity with reasonable metal stresses. With higher steam pressures and capacities, fire tube boilers would need large diameter shells and with such large diameters, the shells would have to operate under such extreme pressure and temperature stresses that the thicknesses would become very large. The fire tube boilers also subjected to large scale deposit and susceptible to boiler explosions and become very costly.

The water tube boiler may have straight tubes; bent tubes or tubes formed in the shape of coils. The furnaces of water-tube boilers normally have brickwork or ceramic baffles so arranged that the products of combustion are forced through the generating tube banks two or more times. The arrangement permits the maximum amount of the heat to be transferred through the tube wall to the water and steam and increases the efficiency of the boiler.

Below are advantages of water tube boiler:

- Water tube boiler is safer.
- The drum is not at the hottest part of the furnace. If there is tube rupture only a small amount of water is instantly released to flash into steam.
- Water tube boilers in the larger sizes are faster steamers because of their large heating surface long gas travel and rapid and positive water circulation.
- The water tube boiler can be operated at high pressure.

The majority of water tube boilers come in field-erected boilers type. Field-erected boilers are not limited to size as in the case of packaged boilers. Normally the design is

in accordance with the customer's needs. Hence they are many different types and sizes that may be selected for installation and erection in the field at the location where the boilers are to be used. For this type of boiler, the boiler manufacturer has total involvement in the installation of the boiler. The majority of the field erected boilers are of the water tube type.

2.2.2.1 Straight Tube Boiler

This is the old version of water tube boiler having straight tubes. The tubes are placed in the furnace and the drum above is used primarily as a storage tank for water and steam. Circulation from the drum is down the back headers, through the water tube and up through the front header.

There are two types of drum in straight tube boiler, longitudinal drum and cross drum. The longitudinal drum type has the drum or drums parallel to the inclined tubes and above the headers. A single longitudinal drum could accommodate only a limited number of tubes and hence a limiting heating surface. Longitudinal drum boilers were limited to low pressures of 12 to 23 bar and steam capacities of 0.63 to 10 kg/s, having heating surfaces of 93 to 930 m².

The cross-drum type has tubes running from the upper part of the front header (or headers) to the drum, and then entering the drum steam space. Cross drum boilers could accommodate many more tubes than longitudinal drum boilers because of their geometry and were built with heating surface of 93 to 2200 m², pressures of 12 to 100 bar and steam capacities of 0.63 to 63 kg/s.

Straight tube boiler had many disadvantages, for examples:

- It has less accessibility and poorer inspection capability. Considerable time, labor and expense were required to open up or closed the bolts in the headers and to remove or replace the gaskets and handhole caps for tube inspection or replacement

- Inadequate design and imperfection fabrication of handhole caps resulted in much leakage, which was a continuous source of annoyance to the operators.
- Circulation was sluggish due to low head and limited steam disengaging surface made inadequate separation of steam and water reducing steam rate.

2.2.2.2 Bent Tube Boilers

Bent tube boilers offered many advantages over the straight tube ones, for examples are greater accessibility for inspection, cleaning and maintenance and ability to operate at higher steaming rates and also to deliver drier steam. In a bent tube boiler, the tubes were so bent that the tubes entered and left the drums radially.

2.3 Essential Fittings

For boilers to be operated safely, certain fittings are required on all boilers. These fittings are called essential fittings. These fittings are part of the requirements of good engineering practices and form the major regulations of Department of Occupational Safety and Health (DOSH). The function of each of these fittings must be fully understood by those who involved in boiler operation. The essential fittings that had been predetermined by DOSH are as follows:

1. Water Gauge Glasses
2. Safety Valves
3. Steam Pressure Gauge
4. Blow down Valve
5. Feed Pumps
6. Main Stop Valve
7. Feed Check Valve
8. Inspector Test Pressure Gauge Attachment
9. Fusible Plug
10. A Low-water Alarm
11. A Low-water Fuel Cut-out
12. Manufacturer's of Makers Name Plate and
13. A Registration Plate

2.4 Authorized Safe Working Pressure.

A safe working pressure for a boiler is assigned by the Chief Inspector. An operator is not allowed to operate a boiler at a pressure that is higher than this. This authorized safe working pressure is normally marked in red on the pressure gauge. If a boiler is operated at a pressure that is higher than the authorized safe working pressure, it is very risky and against the law.

2.5 Pressure Safety Valve (PSV)

PSV is an automatic pressure relieving device actuated by the static pressure up stream of the valve, and characteristic by rapid full opening or pop action. It used for steam, gas or vapor service. It is able to pop wide open rather open gradually by huddling chamber located below the disc.

PSV had been used in boiler to release excess pressure of the steam produced. PSV opens with a sharp pop when the pressure inside steam drum is 3% overpressure from the set pressure. As inlet pressure decays below the opening pressure, the PSV remains open until a pressure about 4% below the set pressure is reached. At this point the PSV will close sharply.

2.5.1 Definition of Important Terms

- **Set pressure** – the pressure which the valve begin to lift-off the seat
- **Popping pressure** – the pressure which the valve actual pop open
- **Back pressure** – the static pressure existing at outlet of a pressure relief device due to pressure in the discharge system

2.5.2 Pressure Safety Valve Components

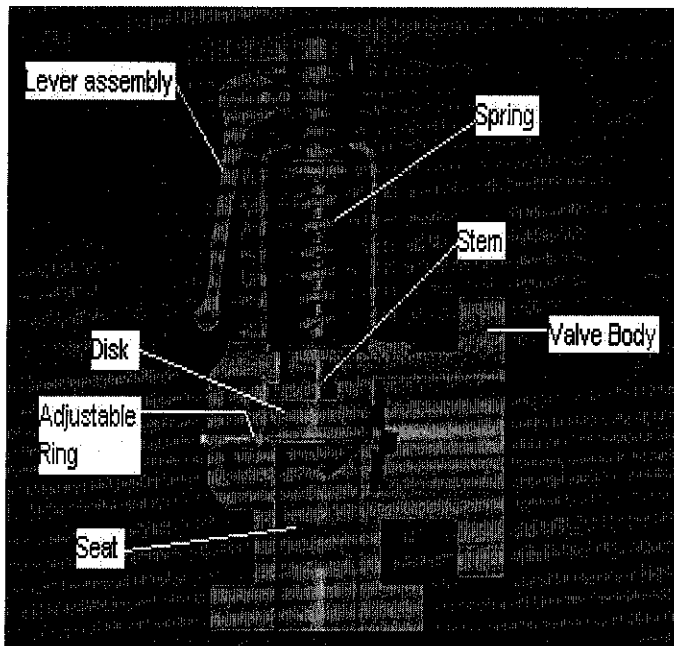


Figure 2.1: Pressure Safety Valve (PSV) main components

- **Adjustable ring** – direct the escaping steam and the principle blowdown control
- **Disc and seat** – seal the system close under a normal pressure.
- **Stem** – mount the disc
- **Spring** – hold the disc on it place.
- **Lever assembly** – trigger the valve manually while system operates.
- **Valve Body** – direct the flow of the steam.

2.5.3 Working Principle of Pressure Safety Valves (PSV)

Simmering occurs before the PSV fully open. During simmering the disk is only slightly lifted and the valve discharged a small amount of steam. Simmering will last for only a fraction of a second until the system pressure act on the lip of the disc. As the disk lift, the lip of the disk is suddenly exposed to the system pressure. Since the larger area of the disk is now exposed to the system pressure, more force is being exerted on the bottom of the disk. This increase force will overcome the spring tension and causes the disc to pop open to about 60% of open position.

When the valve popping pressure had been reached, the valve should be open with a clean and sudden pop. If the pressure in the system continues to increase, the velocity of the escaping steam will also increase and cause the disk to gradually lift higher until it reached the fully open position. Since the initial opening of the safety valve is about 60 %, a large volume of steam is allowed to escape quickly. After the access pressure had been relief, the system pressure will begin to drop.

As pressure decrease, the velocity of the escaping steam also decreases. Spring tension begins to take over pushing the disk down. The spring tension and safety valve had been preset and it must be correct for the valve to operate properly. When the system pressure drop to the point of set pressure, the valve does not close since the lips still exposed to the velocity of the escaping steam. When the systems pressure drops to predetermine value below the popping pressure, the disk begins to drop down to the seat, closing the valve. This predetermined value is called the valve reseating pressure.

When the disk is firmly placed against the seat, the valve is said to have positive seating. Positive seating is important, because it keep the valve from steam leakage through the disk.

A reduction in steam temperature results in loss in plant efficiency. For example, a drop of about 20 °C in steam temperature results in about 1% increase in heat rate. On the other hand, a rise in steam temperature above design value may result in overheating and failure of superheater and reheater tubes or turbine blades.

The temperature of the saturated steam leaving the drum corresponds to the boiler pressure and remains constant if the steam-pressure controls are in working order. It is the superheater-reheater responses to load changes which need to be corrected.

2.6 Blowdown

Blowdown is an integral part of the proper functioning of a boiler water treatment program and usually requires continuous monitoring for positive control. It is through blowdown that most of the dirt, mud, sludge and other undesirable materials are removed from the boiler drum.

In most systems, surface blowdown is accomplished continuously and the optimum blowdown interval is such that sludge or scale on heating surfaces is minimized. At the same time, the loss of heat and chemical additives is also kept to a minimum.

In the larger, more critical boilers, continuous surface blowdown is usually combined with a regular bottom blowdown. In many high pressure boilers, it is desirable to minimize boiler blowdown to reduce heat and water losses.

Blowdown analysis is accomplished by sample conditioning considerations but the control parameter is generally conductivity. Typically, a conductivity meter limit is maintained within a control range and blowdown is activated by a certain deviation from that range. Other blowdown monitoring parameters include pH, silica, hydrazine and phosphate.

Intermittent or bottom blowdown is taken from the bottom of the mud drum, waterwall headers or lowest point in the circulation system. The blowoff valve is opened manually to remove accumulated sludge, about 4 to 8 hours or when the boiler is idle or on a low-steaming rate. But hot water is wasted and control of concentrations is irregular and requires operator trial-and-error to establish quantity and time of blowdown.

Continuous surface blowdown automatically keeps the boiler water within desired limits. Continuously removing a small stream of boiler water keeps the concentration relatively constant. Savings by transferring heat in the blowdown to incoming makeup often pay for the investment.

2.6.1 Percentage Blowdown Calculation

Amount of blowdown is calculated as a percentage of makeup water flow into the boiler in order to keep the concentration of impurities in the boiler at an acceptable level or at acceptable ppm (part per million). If no blowdown is performed, the solids concentration in the makeup water would add to the existing solids concentration as steam is evaporated. Blowdown removes the concentrated impurities to acceptable boiler water concentrations.

2.7 Boiler Feedwater

2.7.1 Introduction

With the trend to high pressure boilers, pretreatment has become the key to successful operating industrial power plants. The composition of boiler feedwater must be such that the impurities can be concentrated in the boiler a reasonable number of times without exceeding the tolerance limits of the boiler design. If the feedwater does not meet this requirement, it must be pretreated to remove impurities. Any impurities not completely removed are chemically treated to control deposition, carryover and corrosion in the boiler system.

Boiler feedwater is water added to a boiler to replace evaporation and blowdown. In many cases, condensed steam return to the boiler through the condensate system constitutes much of feedwater. Makeup is any water needed to supplement the return condensate. The makeup water is usually natural water, either in its raw state or treated by some process before use. Feedwater composition therefore depends on the quality of the makeup water and the amount of condensate returned.

2.7.2 External and internal feedwater treatment

External treatment is the reduction or removal of impurities from water outside the boiler. External treatment reduces feedwater impurities to levels tolerable by

the boiler system. Internal treatment is the conditioning impurities within the boiler system. The reactions occur either in the feed lines or in the boiler itself. The purpose of internal treatment is to properly react with feedwater hardness, control corrosion, scavenge oxygen and prevent boiler water carryover.

2.7.3 Why water treatment is needed

2.7.3.1 Water impurities cause deposits

As feedwater enter a boiler, heat cause hardness (calcium and magnesium salts) to precipitate. Left untreated, the hardness will deposit on the hot boiler metal to form scale. As water evaporates in the boiler, the feedwater impurities concentrate. In higher pressure boilers, even small amounts of iron, copper and silica can accumulate and cause serious deposit problems. Since scale can cause overheating a metal failure, preventive chemical treatment is needed. The biggest problem that deposits cause is tube failures from overheating. A deposit acts as an insulator and excessive deposits prevent efficient heat transfer through the tube to the circulating water. This cause the metal becomes overheated. When the overheating is severe enough and long enough, the metal failed.

2.7.3.2 Water corrodes boiler metal

The corrosion of boiler system metal is a complex process and takes many forms; general attack, localized pitting and various types of stress cracking. Corrosion is the reversion of a metal to its original form. In general, the main factors causing the boiler corrosion are dissolved gases in water (primarily oxygen) and extreme pH conditions. High temperatures accelerate the corrosion process. Corrosion is damaging from several standpoints. It generally causes weakening and metal failure and produces corrosion products, which can cause boiler deposits.

2.7.3.3 Poor purity of water gives poor purity steam

High concentration of dissolved and suspended matter in boiler water can cause foaming at the steam release surface. This produces carryover of the water and its impurities into the steam. Carryover results in deposits, corrosion and contamination in superheaters, turbines and other process using steam. While mechanical and operational factors also cause carryover, proper control of water conditions is important in producing good quality of steam. Boiler water carryover is the contamination of steam with boiler water solids.

2.7.4 Removing Impurities from Water

2.7.4.1 Coagulation and Precipitation

Coagulants are chemicals used to charge neutralize fine particles of suspended matter in a water supply to form a flock that settles or can be filtered out. Adding softening chemicals such as lime, soda ash and sodium aluminate to water causes some dissolved hardness salts to precipitate. The suspended matter can then be coagulated and filtered. Precipitation processes such as lime-soda softening can effectively remove suspended matter, hardness, total dissolved solids and alkalinity and in some cases reduce silica content of the water.

2.7.4.2 Ion Exchange Process

When a salt dissolved in water, it forms a positive ions (cations) and negative ions (anions). For example, calcium bicarbonate, $\text{Ca}(\text{HCO}_3)_2$ forms a calcium cation (Ca^{2+}) and bicarbonate anion (HCO_3^-). The most common form of ion exchange involves passing water through a resin material that substitutes sodium for calcium and magnesium cations. This is a typical softening treatment. Anions can also be removed from water by the use of special ion exchange resins. Demineralization or complete removal of dissolved minerals involves the use of both anion and cation exchange resins.

2.7.4.3 Other methods

Other methods are deaeration (heating of water and venting the release gases) for reduction of oxygen and carbon dioxide. Evaporation to produce distilled water and reverse osmosis to reduce all dissolved minerals is also ways to remove impurities.

2.7.5 Treating Boiler Feedwater

2.7.5.1 The Purpose of Treatment

Since even small amounts of dissolved and suspended water impurities can cause problems, chemical treatment is needed regardless of how the feedwater is prepared. A complete boiler water treatment may include:

1. chemicals may react to feedwater hardness
2. natural or synthetic sludge conditioners to prevent suspended solids from sticking to the boiler metal
3. oxygen scavengers to prevent corrosion
4. chemicals antifoams to prevent carryover

2.7.5.2 How Treatment is Controlled

Proper proportioning and feeding of chemicals is needed to ensure that the recommended amount of treatment is maintained continuously. Regular water tests as well as continuous analyzer provide the basis for controlling the boiler treatment program. Automated control systems are becoming more common. The use of tracers has proven to be a more effective method to control the boiler than proportional control or control related to boiler feedwater flow. In addition, to maintaining proper treatment levels, proper control requires blowing down boiler water to reduce the level of suspended solids and dissolved solids to a safe operating level.

2.8 Basic Consideration in the Analysis of Power Cycle

Most power producing devices operate on cycles and the study of power cycles is an important part of thermodynamics. When the actual cycle is stripped off all the internal irreversibilities and complexities, the cycle is end up with a cycle that resembles the actual cycle closely but is made up totally of internally reversible processes. Such a cycle is called an ideal cycle.

A simple idealized model enables engineers to study the effects of the major parameters that dominate the cycle without getting bogged down in the details. The conclusions reached from the analysis of ideal cycles are also applicable to actual cycles.

Heat engines are designed for the purpose of converting other forms of energy, usually in the form of heat to work and the performance is expressed in terms of the thermal efficiency, which is the ratio of the net work produced by the engine to the total heat input:

$$\eta_{th} = \frac{W_{net}}{Q_{in}}$$

Heat engines that operate on a totally reversible cycle, such as Carnot cycle have the highest thermal efficiency of all heat engines operating between the same temperature levels. Most cycle encountered in practice differ significantly from the Carnot cycle because of hardware related, which makes it unsuitable as a realistic model.

The ideal cycles are internally reversible, but unlike the Carnot cycle, the cycles are not necessarily externally reversible. That is, the cycles may involve irreversibilities external to system such as heat transfer through a finite temperature difference. Therefore, the thermal efficiency of an ideal cycle, in general is less than of a totally reversible cycle operating between the same temperature limits. However, it is still considerably higher than the thermal efficiency of an actual cycle because of the idealization utilized.

The idealizations and simplifications commonly employed in the analysis of power cycles can be summarized as follows:

- a) The cycle does not involve any friction. Therefore, the working fluid does not experience any pressure drop as it flows in pipes or devices such as heat exchanger.
- b) All expansion and compression processes take place in a quasi-equilibrium manner. (internally reversible)
- c) The pipes connecting the various components of a system are well insulated, and heat transfer through these components is negligible.

Neglecting the changes in kinetic and potential energies of the working fluid is another commonly utilized simplification in the analysis of power cycles. This is a reasonable assumption since in devices that involve shaft work such as turbines, compressors and pumps, the kinetic and potential energy terms are usually very small relative to the other terms in the energy equation. Fluid velocities encountered in devices such as condensers, boilers and mixing chambers are typically low and the fluid streams experience little change in the velocities, again making kinetic energy changes negligible.

Property diagrams such as P - v and T - s diagrams are valuable aids in the analysis of thermodynamic processes. On both P - v and T - s diagrams, the area enclosed by the process curves of a cycle represents the net work produced during the cycle, which is also equivalent to the net heat transfer for that cycle. The T - s diagram is particularly useful as a visual aid in analysis of ideal power cycles. An ideal power cycle does not involve any internal irreversibilities, and so the only effect that can change the entropy of the working fluid during a process is heat transfer.

On a T - s diagram, a heat addition process proceeds in the direction of increasing entropy, a heat rejection process proceeds in the direction of decreasing entropy and an isentropic (internally reversible, adiabatic) process proceeds at constant entropy. The area under the process curve on a T - s diagram represents the heat transfer for that

process. The area under the heat addition process on a $T-s$ diagram is a geometric measure of the total heat supplied during the cycle q_{in} , and the area under the heat rejection process is a measure of the total heat rejected q_{out} . The difference between these two areas enclosed by the cyclic curve is the net heat transfer, which is also the net work produced during the cycle. Therefore, on a $T-s$ diagram, the ratio of the area enclosed by the cyclic curve to the area under the heat addition process curve represents the thermal efficiency of the cycle. Any modification that will increase the ratio of these two areas will also improve the thermal efficiency of the cycle.

Although the working fluid in an ideal power cycle operates on a closed loop, the type of individual processes that comprises the cycle depends on the individual devices used to execute the cycle. In the Rankine cycle, which is the ideal cycle for steam power plants, the working fluid flows through a series of steady flow devices such as turbine and condenser. Therefore, equation pertaining to steady flow systems should be used in the analysis of the Rankine cycle.

2.9 Basic combustion process

The combustion process is a special form of oxidation in which oxygen from the air combines with fuel elements which generally are carbon, hydrogen, and detrimental, sulphur. A proper mixture of fuel and air as well as an ignition temperature is required for the combustion process to continue. Fuel must be prepared so that thorough mixing of fuel and air is possible.

In steam boiler practise, a combustible is a substance capable of combining with oxygen to liberate heat, yet it is usual to employ the term to cover the portion of the fuel remaining after the subtraction of moisture and ash. But, this is not strictly correct, for there are incombustible constituents in the fuel, nitrogen and the oxygen which is spent because it is already in combination and not available for the process of combustion.

Three conditions must be satisfied for chemical reactions to take place in the combustion process:

- a) Proper proportioning of fuel and oxygen (or air) with the fuel elements
- b) The mixing of fuel and oxygen must be thorough, so a uniform mixture is present in the combustion zone and so every fuel particle has air around it to support the combustion. Solid fuels generally will be converted to gas first by the heat and presence of air. Liquid fuels will vaporize into gases and then burn. Atomization of liquids increases the mixing with air and increases the vaporization into a gas.
- c) The ignition temperature must be established and monitored so that the fuel will continue to ignite itself without external heat when combustion starts.

The chief heat-producing elements in fuels are carbon, hydrogen and their compounds. Sulphur, when rapidly oxidized is also a source of some heat energy, but its presence in a fuel has bad effects. Since oxygen in the air is 23.25 % by weight and 21 % by volume, the amount of air required can be calculated. For example, in the complete combustion of carbon, it can be determined that 2.67 % lb of oxygen is required to burn 1 lb of carbon. The amount of air required to burn 1 lb of carbon would then be

$$A_R = \frac{\text{Amount of oxygen}}{\% \text{ oxygen in air by weight}} = \frac{2.67}{0.2315} = 11.52 \text{ lb}$$

Incomplete combustion results in smoke and lowered operating efficiency. In order to obtain complete combustion, the furnace volume must be adequate to permit complete burning of fuel particles before entering heating surfaces and are cooled below the ignition temperature.

If not enough oxygen or air is supplied, the mixture is rich in the fuel, thus the fire is reduced with a resultant flame that tends to be longer and smoky. The combustion also is not complete and the flue gas (product of combustion) will have unburned fuel such as carbon particles or carbon monoxide instead of carbon dioxide. Less heat will be given off by the combustion process. If too much oxygen or air is supplied, the mixture

and burning will lean, resulting in a shorter flame and cleaner fire. Excess air takes some of the released heat away from the furnace and carries it up the stack. Burning should always be with excess air to ensure that all the fuel is properly burned and thus attain better efficiency in heat release. This also reduces smoke formation and soot deposits.

When flue gas comes out of a stack as black smoke, it is an indication of insufficient air. Too much air usually causes a dense, white smoke. A faint, light-brown haze coming from the stack is a sign of a reasonably good air-fuel ratio.

2.10 Air Fuel Ratios

Air fuel ratios are being trimmed to as low a level as possible as a means of saving fuel. However, unless excess air is used in the combustion chamber, incomplete combustion can occur, which also wastes fuels and there is a risk of a late-ignition-type furnace explosion occurring from unconsumed fuel. In order to ensure complete combustion, excess air must be supplied in amounts varying from 20 % to 30 %, depending on the fuel used, the boiler load and boiler configuration. The correct amount of excess air is also influenced by the need to control NO_x and SO₂ emission.

Combustion analyzers used infrared absorption techniques to provided readings of CO and CO₂, which can be fed to a controller with input signals on boiler load. Feed-forward concepts are used to automatically control air dampers as a function of load, while the controller also alters the relationship between the air damper and the fuel valve as the boiler firing rate changes with load. The system is called an automatic boiler combustion trim control. As can be noted, its main purpose is to maintain a constant air-fuel ratio.

2.11 Boiler Efficiency Monitoring

Boiler efficiency monitoring can reveal degradation that if stopped and corrected can improve boiler performance in technical and financial ways by perhaps reducing fuel

costs. There are two methods in calculating boiler efficiency for monitoring of boiler performance.

2.11.1 Direct method

This is the simplest and easiest way where:

$$\text{efficiency} = \frac{\text{output}}{\text{input}} \times 100$$

It is necessary to stabilize boiler conditions to agreed set points so that comparisons can be made to the same boiler operating conditions. This simplified method of tracking efficiency can be used to detect trends of performance by comparing previous efficiencies with current results. The best comparison is obtained with a benchmark reading when boiler is new or after a thorough cleaning and overhaul.

2.11.2 Indirect Method

This method is also called the input-loss method and closely follows the American Standard of Mechanical Engineering (ASME) method of tabulating where the losses are occurring. The efficiency is then determined by:

$$\text{efficiency} = \frac{\text{input} - \text{losses}}{\text{input}} \times 100$$

This method requires measuring the flue gas and also a fuel ultimate analysis. Its chief advantage is that it indicates where the losses are occurring, thus making it possible to improve the efficiency if the identifiable losses can be reduced. Its disadvantage is that much data and calculations are necessary.

The following losses must be determined in the indirect method:

- a) Loss due to moisture in the fuel. This is especially applicable to coal that is washed or stored outdoors. For other fuels, it is considered an inherent loss with little chance for improvement unless there is a fuel change.

- b) Loss due to the combustion of hydrogen in the fuel that also forms moisture and goes up the stack as vapor. Gas and oil have the most hydrogen in them. This loss is also considered an inherent loss and not controllable unless the fuel specifications are changed.
- c) Loss due to moisture in the air used for combustion. This is one of the reasons large-sized boilers preheat the air. Otherwise, it is also considered an inherent loss originating from the use of ambient air in the combustion of the fuel.
- d) Loss due to the heat carried up the stack by the flue gas. Factors that can influence this loss item include:
 - High excess-air as revealed by flue-gas analysis.
 - Dirty or scaled water-side and fire-side heat transfer surfaces.
 - Poor water circulation in comparison to fireside gas flows.
 - Faulty gas baffles that permit bypassing of heat transfer surfaces
 - Gas velocity through boiler too high resulting not enough time is available for efficient heat transfer.
- e) Losses due to incomplete combustion from:
 - Insufficient air supply.
 - Cool furnace at low loads.
 - Poor atomization or pulverization of fuel.
- f) Losses due to combustible in ash, especially applicable to solid fuel-burning boilers, caused by:
 - Grate not large enough for complete combustion of the fuel.
 - Too high solid fuel injection or overload on boiler.
 - Too frequent dumping of ash before complete combustion of the fuel occurs.
- g) Miscellaneous losses from radiation, convection and leaks, such as:
 - Poor insulation around drums and setting.
 - Furnace refractories in need of repair.
 - Piping , joints, seal and other leaks around boiler setting.

CHAPTER 3

METHODOLOGY/PROJECT WORK

Appropriate methodology had been set up to ensure the project can be done flawlessly. The methodology is also a useful guide for the student in conducting the project. The subsections of the methodology are:

1.1 Study Working Principle of the Boiler

Firstly, the concept and theory of boiler and steam has to be study to gain plenty of knowledge regarding to what the student deal with through out the project. The study also includes the supporting equipments to the boiler such as pressure safety valve (PSV. Further study on boiler feed water is also carry out since boiler feed water can lead to boiler problems.

1.2 Relate with Theory

The first law of Thermodynamics state the energy is conserved during a process. The second law of Thermodynamics state that processes occur in a certain direction and the energy has quality as well as quantity. A process cannot take place unless it satisfies both the first and second law of Thermodynamics. The heat engine such as steam power plant obeys both of this law. Further study on energy, exergy, enthalpy and entropy is also carry out since these properties affect the steam production.

1.3 Further Study on Boiler Operation

A site visit to power plant had been included in planning. The visit purpose is to learn the boiler operation and maintenance in industries. This also includes the pre-start check, start up procedure and shut down procedure.

1.4 Operate the Mini Steam Power Plant

The Mini Steam Power Plant in Power Generation Lab will be operated to investigate the steam production and power produced. The performance, thermal efficiency and emission will be calculated.

1.5 Data Analysis/Discussion

The results obtained will be analyzed and further discussion with the supervisor will be conducted. The discussion will be based on how to increase the boiler performance as well as to optimize the boiler operation and maintenance. The data will be compared with the manual given from the manufacturer of the boiler.

1.6 Equipment Used

Mini steam power plant used in UTP Power Generation Lab is a type of BRADLEE firetube boiler. The BRADLEE boiler is of the 3-pass horizontal, returns flame, wet-back type and is of all-welded construction, designed for working pressures up to 105 or 150 psig. The shell has heavy duty tubes expanded and welded into heavy steel tube plates and is well insulated and clad over-all with a sheet steel jacket. The fire-box is integral with the shell. The operational pressure of this boiler is set to be at 9 bar. The boiler required time between 20 minutes to 30 minutes to reach the operational pressure from start up. The layout of the steam power plant is shown in Figure 3.1 (refer to Appendix 3.1). The diagram of the boiler system is shown in Figure 3.2 (refer to Appendix 3.2).

The type of experiments that can be conducted using the steam power plant is as listed below:

- a) Air Compressor Test Set
- b) Additional Boiler Instrumentation
- c) Separating and Throttling Calorimeter
- d) Steam Turbine and Condenser Unit
- e) Steam Flow Measuring System

- f) Water Treatment Set
- g) Additional Superheater Instrumentation

Since the boiler faced a lot of problems throughout the semester, based from discussion with the supervisor, the project will be covered with the calculation and review of 3 types of experiments only. The experiments are:

- a) Additional Boiler Instrumentation
- b) Steam Flow Measuring System
- c) Separating and Throttling Calorimeter

1.7 Experimental Procedure

1.7.1 Additional Boiler Instrumentation

- a) The boiler is set to raise steam at the required conditions and is allow the condition to stabilize. Note the time and run the boiler on load, taking note of quantities of fuel and feedwater used during the test.
- b) The dryness fraction of the steam from the boiler is measured using separating and throttling calorimeter and the flue gas should be analyzed using the gas analyzer.
- c) The reading of the quantities listed on the specimen results sheet was taken and the average is use for calculation purpose.
- d) The sample of result sheet used for this experiment is shown in Table 3.1.
(Refer to Appendix 3.3)

1.7.2 Steam Flow Measuring System

There is no appropriate procedure provided for this experiment but as long as the boiler is run, the data can be taken and being used for calculation purpose. The observation log sheet is shown in table on the next page:

Steam orifice: differential pressure (mbar)	
Steam orifice: differential pressure (°C)	
Steam orifice: differential pressure (bar.g)	
Steam Line : dryness fraction of steam	

Table 3.2: Observation log sheet

1.7.3 Separating and Throttling Calorimeter

- a) The cooling water flow is started through the condenser and the condensate collecting vessel is placed under the condenser outlet.
- b) The small valve on the throttling calorimeter is closed to isolate the manometer.
- c) The steam valve is open and allows the steam to flow through the calorimeters to warm up the system. The water flow through the condenser must be sufficient to condense all the steam.
- d) The valve to the manometer is open when the condition is stabilised.
- e) The separated condensate level is allowed to build up in the separating calorimeter until liquid can be seen in the calorimeter condensate level tube. Then, the main condensate collecting vessel is drained.
- f) After that, the main condensate collecting vessel under the condenser outlet is refilled.
- g) The initial value of fluid level in the separating calorimeter, the initial value of condensate level in the main condensate collecting vessel, the steam pressure in the steam main, steam pressure after throttling, steam main steam temperature and the temperature in the throttling calorimeter were measured and recorded.
- h) Allow time for a reasonable quantity of condensate to collect in the main condensate collecting vessel, and then the quantity is measured. At the same time, the value of fluid level in the separating calorimeter is recorded.
- i) Then, the steam supply is turned off and the valve is closed to isolate the manometer. Allow the apparatus to cool and the condenser cooling water is turned off.

- j) Finally, the separating calorimeter is drain out and then empty the condensate collecting vessel.
- k) The observation log sheet is shown in Table 3.4 (Refer to Appendix 3.4)

CHAPTER 4

RESULTS AND DISCUSSIONS

4.1 Data Gathering and Analysis

4.1.1 Additional Boiler Instrumentation

The objectives of this experiment are to estimate the steam raising capacity of the boiler when operating at a given pressure and to draw up an energy balance for the boiler unit.

4.1.1.1 Energy Balance

The net change (increase or decrease) in the total energy of the system during a process is equal to the difference between the total energy entering and the total energy leaving the system during that process. That is, during a process in a system;

Total energy entering - Total energy leaving = Change in the total energy

$$E_{in} - E_{out} = \Delta E_{system}$$

This relation is often referred to as the energy balance and is applicable to any kind of system undergoing any kind of process. The successful use of this relation to solve engineering problems depends on understanding the various forms of energy and recognizing the forms of energy transfer.

4.1.1.2 Heat Balance for 1kg of Fuel

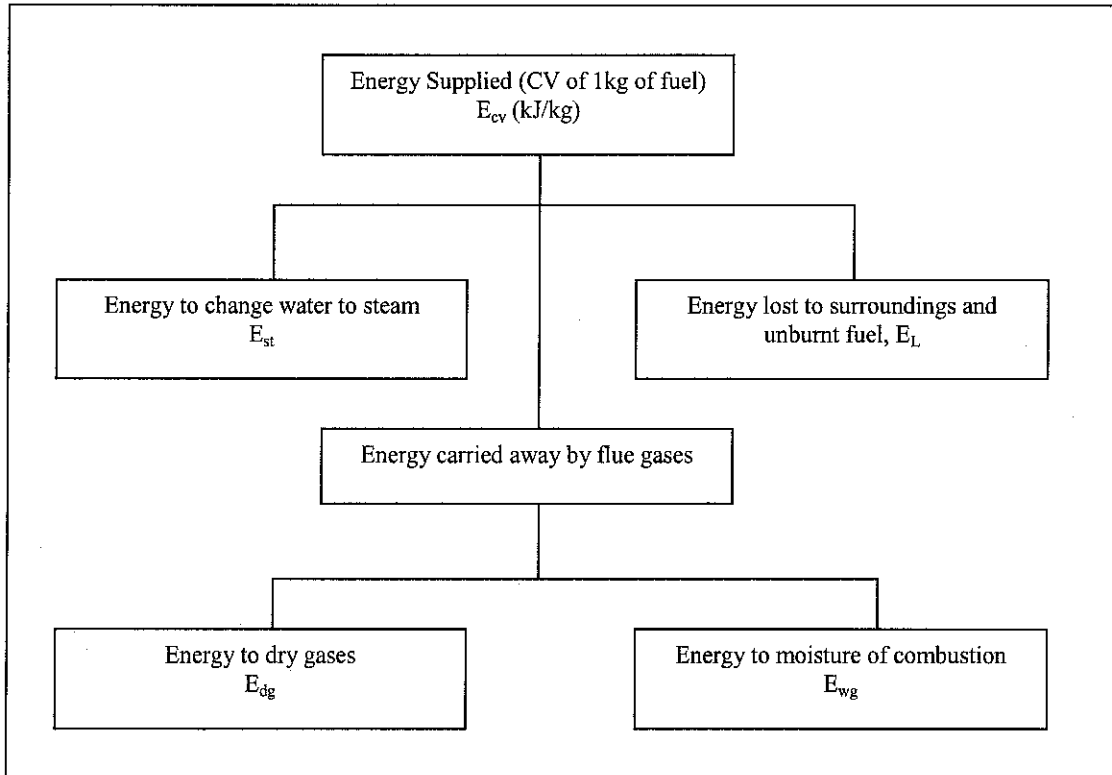


Figure 4.1: Heat balance diagram

- a) E_{cv} – this value is the energy supplied by a kilogram of the fuel and is obtained from the suppliers published data or from the results of a ‘Bomb’ calorimeter experiment. The value also might be calculated using the results of chemical analysis of the fuel together with published calorific value data for the fuel elements.
- b) E_{st} – the energy to change the feedwater into steam is the enthalpy of the steam generated, less the enthalpy of the feedwater.

$$E_{st} = m_w (h_s - h_{fw}) \text{ kJ/kg}$$

- c) $E_{dg} + E_{wg}$ – the energy given to the flue gases is obtained from the gas flow rate, the mean specific heat (includes water content) of the flue gases, the mean temperature of the flue gases and the surrounding air.

$$E_{dg} + E_{wg} = m_g C_g (t_{fl} - t_{at}) \text{ kJ/kg}$$

- d) E_L – the energy lost is calculated from

$$E_{cv} - (E_{st} + E_{dg} + E_{wg}) \text{ kJ/kg}$$

4.1.1.3 Calorific Value of the Fuel

The calorific value of a solid or liquid fuel may be obtained approximately from a chemical analysis of a sample. The sample fuel analysis will give the p.u. values of the constituents in a dry sample. The constituents considered are usually carbon, hydrogen, sulphur, nitrogen, oxygen and residual ash. Of these elements only carbon, hydrogen and sulphur contribute significantly to the calorific value.

If hydrogen in a fuel is allowed to be completely burnt to form water, 143 MJ/kgm are liberated (this gives the Higher Calorific Value for the fuel). However, if the water vapor initially formed is not allowed to condense, the heat liberated will only be 120.5 MJ/kgm (this gives the Lower Calorific Value for the fuel). The Calorific Value obtained from a 'bomb' calorimeter experiment is the higher one and this is the figure used for calculations of boiler performance and efficiency.

At 25 °C, the difference between the calorific values at constant volume is:

$$205.8 H + 23 W \text{ kJ/kgm,}$$

Where,

H = percentage of hydrogen in the fuel,

W = percentage of water in the fuel

4.1.1.4 Boiler Efficiency

Boiler efficiency = (energy gained by fluid/ total energy input)

Total energy input = flowrate X calorific value of fuel

Energy gained by fluid = $M_1 (h_s - h_{fw}) = M_t (h_s + c_p [t_{fw} - 0])$

The absolute pressure of steam = gauge pressure + atmospheric pressure

$$= P_g + (H \times 13600 \times 9.81) / 105$$

$$= P_g + 1.3342H$$

Where,

P_g = gauge pressure in bars

H = barometric pressure in mm of mercury

Thus, boiler efficiency = $M_t(h_s - h_{fw}) / (m_f CV_f)$

Where,

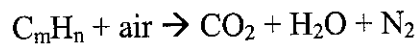
M_t = kg of steam produced per hour (kg/hr)

CV_f = calorific value of fuel (kJ/kg)

4.1.1.5 Combustion of a Hydrogen Carbon Fuel C_mH_n

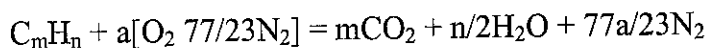
Any material that can be burned to release energy is called a fuel. Most familiar fuels consist primarily of hydrogen and carbon. They are called hydrocarbon fuels and be denoted by the general formula C_mH_n . Hydrocarbon fuels exist in all phases, some examples being coal, gasoline and natural gas.

The combustion equation is basically:



For perfect combustion the theoretical amount of air required is defined as that quantity which contains just enough oxygen for complete oxidation of the constituents of the fuel. As air consists of approximately 77% nitrogen and 23% oxygen by weight then the amount of air may be written as a $[O_2 + (77/23N_2)]$

Since both sides of a chemical equation must balance as regards molecular weights, then:



4.1.1.6 Theoretical Value of Air Supply for Complete Combustion

A combustion process is complete if all the carbon in the fuel burns to carbon dioxide, CO_2 , all the hydrogen burns to water, H_2O and all the sulphur (if any) burns to sulphur dioxide, SO_2 . That is, all the combustible components of a fuel are burned to completion during a complete combustion process. Conversely, the combustion process is incomplete if the combustible products contain any unburned

fuel or components such as carbon, C, hydrogen, H₂, carbon monoxide, CO or hydroxide, OH.

Insufficient oxygen is an obvious reason for incomplete combustion, but it is not only the one. Incomplete combustion occurs even when more oxygen is present in the combustion chamber than is needed for complete combustion. This may be attributed to insufficient mixing in the combustion chamber during the limited time that the fuel and the oxygen are in contact. Another cause of incomplete combustion is dissociation, which becomes important at high temperatures.

Oxygen is more strongly attracted to hydrogen than it is to carbon. Therefore, the hydrogen in the fuel normally burns to completion, forming H₂O even when there is less oxygen than needed for complete combustion. Some of the carbon however ends up as CO or just as plain C particles in the products.

The minimum amount of air needed for the complete combustion of a fuel is called the stoichiometric or theoretical air. Thus, when a fuel is completely burned with theoretical air, no uncombined oxygen will be present in the product gases. The theoretical air is also referred to as chemically correct amount of air or 100% theoretical air. A combustion process with less than the theoretical air is bound to be incomplete.

In actual combustion processes, it is common practice to use more air than the stoichiometric amount to increase the chances of complete combustion or to control the temperature of the combustion chamber. The amount of air in excess of the stoichiometric amount is called excess air. The amount of excess air is usually expressed in terms of the stoichiometric air as percent excess air or percent theoretical air.

4.1.2 Steam Flow Measuring System

4.1.2.1 Bernoulli's Equation

Bernoulli's equation is based on the conservation of energy law, which states that energy can be neither created nor destroyed. This means that the total energy possessed by a given mass of fluid as it flows through a system remains constant unless energy is added to or removed from the fluid. For steady, inviscid, incompressible flow and with no heat added or removed, the total energy possessed by a given mass of fluid can be considered to consist of potential energy (PE), kinetic energy (KE) and flow energy (FE).

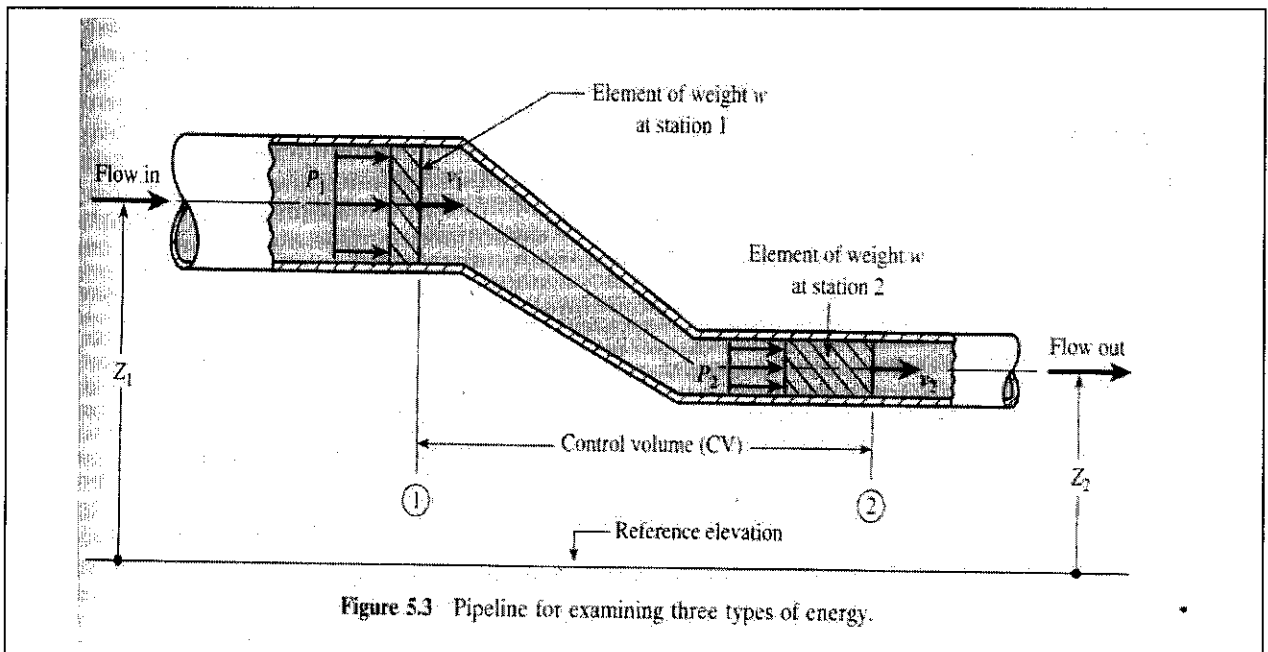


Figure 4.2: Pipeline for examining 3 types of energy

Each of these three types of energy can be examined using figure above which shows fluid flowing from left to right in a pipeline. The total energy possessed by a given weight w of fluid entering the control volume at station 2 can be determined. The figure also shows that the pipe diameter and elevation at station 1 are different from that at station 2.

Total energy in element at 1 = total energy in element at 2

$$\text{Thus, } (PE + KE + FE)_1 = (PE + KE + FE)_2$$

$$Z_1 + (v_1^2)/2g + P_1/\gamma = Z_2 + (v_2^2)/2g + P_2/\gamma$$

4.1.3 Separating and Throttling Calorimeter

4.1.3.1 Dryness Fraction

The dryness fraction of steam is defined as the quantity of dry vapour present in any wet vapour mixture.

$$\text{Dryness fraction} = \frac{\text{Quantity of dry steam}}{\text{Quantity of dry steam} + \text{water}}$$

4.1.3.2 Separating Calorimeter

This is a mechanical process where the incoming steam to the calorimeter is made to travel through a series of obtuse angles where the inertia of the water droplets causes them to separate from the steam flow.

If W_t = quantity of dry steam discharged from calorimeter and W_s = quantity of water separated in the calorimeter in the same interval of time, then the dryness fraction as measured by the separating calorimeter (X_s)

$$X_s = \frac{W_t}{W_t + W_s}$$

4.1.3.3 Throttling Calorimeter

Consider a fluid flowing through a throttling orifice from a higher pressure P_1 to a lower pressure P_2 . From the steady flow energy equation it can be shown that adiabatic throttling is a constant enthalpy process. The wet steam before throttling will become superheated at the lower pressure after throttling.

Enthalpy of wet steam at P_1 before throttling $H_1 = h_{f1} + X_t h_{fg1}$

Enthalpy of superheated steam at P_2 after throttling $H_2 = h_{g2} + c_p (t_2 - t_{s2})$

Since $H_1 = H_2$,

$$h_{f1} + X_t h_{fg1} = h_{g2} + c_p (t_2 - t_{s2})$$

$$X_t = [h_{g2} + c_p (t_2 - t_{s2}) - h_{f1}] / h_{fg1}$$

Where,

h_{f1} = sensible heat corresponding to pressure P_1

X_t = dryness fraction at throttling calorimeter

h_{fg1} = latent heat corresponding to pressure P_1

h_{g2} = enthalpy of steam corresponding to pressure P_2

c_p = specific heat at constant pressure

t_2 = steam temperature at throttling calorimeter

t_{s2} = saturated steam temperature corresponding to pressure P_2

4.1.3.4 Combined Separating and Throttling

If w = quantity of water in steam leaving the separating calorimeter and entering the throttling calorimeter, then by the definition of dryness fraction:

$$X_t = (W_t - w) / W_t \text{ and } w = W_t (1 - X_t)$$

But the separating calorimeter has already removed W_s water. Therefore, total quantity of water is $W_s + W_t$.

Applying this to the definition of dryness fraction:

$$\begin{aligned} X &= [(W_s + W_t) - (W_s + w)] / (W_s + W_t) \\ &= (W_t + w) / (W_s + W_t) \text{ but } w = W_t (1 - X_t) \\ &= [W_t - W_t(1 - X_t)] / (W_s + W_t) \\ &= W_t X_t / (W_s + W_t) \\ &= [W_t / (W_s + W_t)] \cdot X \end{aligned}$$

$$\text{From } X_s = \frac{W_t}{W_t + W_s}$$

Therefore, the dryness fraction $X = X_s \cdot X_t$

4.1.3.5 Throttling Process

A throttling process is one in which a fluid at a higher pressure flows through restriction to a lower pressure without any energy transfer into or out of the fluid and without any significant change to the potential or kinetic energy of the fluid. The pressure drop occurs when the fluid flows through the restriction because the restriction causes a head loss. This head loss occurs only while the fluid is flowing.

The continuity equation (conservation of mass law) leads to the conclusion that in the restriction itself there must be a significant increase in velocity and hence kinetic energy. However, downstream of the restriction, the kinetic energy change is not significant if the pipe diameter downstream is the same as the upstream diameter. If the fluid is a liquid and no vapour is form during throttling, the kinetic energy change will be zero because there is no velocity change. If the fluid is a gas, or vapour is flashed out of the liquid during throttling, then there will be an increase in velocity and kinetic energy downstream. This is because the downstream pressure is lower than the upstream pressure and consequently there is a volumetric expansion. However, the change in kinetic energy is negligible since the amount is relatively small compared with the specific enthalpy.

4.2 Results and Discussions

4.2.1 Additional Boiler Instrumentation

4.2.1.1 Calculation of Calorific Value of the Fuel

Calorific value is the amount of heat generated by a given mass of fuel when it is completely burned. It is measured in Joule/kilogram.

Fuel Element	Higher CV (MJ)		Lower CV (MJ)	
	per Kg	per m ³	per Kg	per m ³
Carbon burnt to carbon dioxide	33.82			
Carbon burnt to carbon monoxide	10.17			
Sulphur	9.30			
Hydrogen	143.00	12.85	120.50	10.73

Table 4.2: Calorific Value of Fuel

If a chemical analysis indicates that:

Carbon	0.80
Hydrogen	0.04
Oxygen	0.14
Sulphur	0.02
Total	1.00

Table 4.3: Chemical Analysis of Fuel

Since the fuel contains oxygen, it is assumed that this is already in combination with the hydrogen present and thus the free hydrogen is amount to:

$$[0.04 - (0.14/8)] = h_{\text{free}} = 0.0225$$

Assuming sufficient oxygen to burn all the carbon to carbon dioxide, fuel calorific value is: $(0.80 \times 33.82) + (0.0225 \times 143) + (0.02 \times 9.3) = 30.46$

4.2.1.2 Calculation of Mean Specific Heat of Flue Gas Leaving a Superheater

The specific heat is defined as the energy required to raise the temperature of a unit mass of a substance by one degree. The calculation of mean specific heat of flue gas required a fuel gas analysis, dry analysis of flue gas and estimate of water content in flue gas.

4.2.1.2.1 Analysis of fuel by weight

Carbon	0.8730
Hydrogen	0.0078
Ash	0.0827
Other constituents	<u>0.0365</u>
	<u>1.0000</u>

4.2.1.2.2 Analysis of dry flue gases by Kane (%)

Carbon dioxide	9.88
Carbon monoxide	0.50
Oxygen	9.82
Nitrogen	<u>80.25</u>
	<u>100.00</u>

The dry gas analysis by volume is converted into an analysis by weight:

	V pu vol. analysis	MW Molar weight	V x MW	pu Mass analysis
Carbon dioxide	0.0988	CO ₂ = 44	4.3472	0.1450
Carbon monoxide	0.0005	CO = 28	0.0140	0.0005
Oxygen	0.0982	O ₂ = 32	3.1424	0.1048
Nitrogen	0.8025	N ₂ = 28	22.4700	0.7497
			<u>29.9736</u>	<u>1.0000</u>

Table 4.4 Dry gas analysis

In 1 kg of dry flue gases, the carbon content is

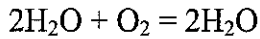
$$[0.1450 \times (12/44)] + [0.0005 \times (12/28)] = 0.0398 \text{ kg}$$

Since there is 0.8730 kg of carbon in 1 kg of fuel and the carbon content of 1 kg of dry flue gas is 0.0398 kg, then the total mass of dry gas produced per kilogram of dry fuel is:

$$0.8730 / 0.0398 = 21.935 \text{ kg}$$

4.2.1.2.3 Estimate of Water Content in Flue Gas

The 0.0078 kg of hydrogen in the 1 kg of fuel will produce steam.



$$4 + 32 = 36$$

$$(36/4) \times 0.0078 = 0.0702 \text{ gm}$$

Thus, true flue gas analysis is:

	Weight of Element per kg of Fuel	pu Value	Sp. Ht. joules per kg - °K
CO ₂	21.935 x 0.1450 = 3.1807	0.1445	830
CO	21.935 x 0.1450 = 3.1807	0.0005	1050
O ₂	21.935 x 0.1450 = 3.1807	0.1045	910
N ₂	21.935 x 0.1450 = 3.1807	0.7473	1040
	21.9350		
+ water content	0.0702	0.0032	2020
	22.0052	1.0000	

Table 4.5 True flue gas analysis

Mean specific heat of flue gases

$$\begin{aligned}
 &= (0.1445 \times 830) + (0.0005 \times 1050) + (0.1045 \times 910) + (0.7473 \times 1040) + \\
 &\quad (0.0032 \times 2020) \\
 &= 999.2 \text{ joules per kg. } ^\circ\text{K}
 \end{aligned}$$

4.2.1.3 Calculation of Boiler Efficiency

Basically, there are 2 methods that can be used to calculate boiler efficiency. For that purpose, indirect method is more likely used rather than direct method since the calculation is more accurate since this method considered the losses incurred.

Taken example here, a boiler uses 2000 lb/hr of coal, which produces 420 lb/hr ash. The unburned carbon in the ash is 18 %. Air and fuel temperature at entrance to furnace is 74 °F. Relative humidity of air is 70%. Barometric pressure is 29.92 in.Hg. Steam temperature is 360 °F. Flue gas temperature leaving the boiler is 452 °F. The following test results were obtained:

Components	Percentage (%)
Carbon, W_c	62.0
Hydrogen, W_h	4.0
Nitrogen, W_n	1.0
Oxygen, W_o	8.0
Sulfur, W_s	2.0
Moisture, W_m	8.0
Ash, W_a	18.0

Table 4.6: Fuel analysis for coal, % per lb coal

Heating value of coal = 11800 Btu/lb

Miscellaneous losses = 4.11% (assumption)

Components	Percentage (%)
CO ₂	13.0
CO	1.0
O ₂	5.0
N ₂	81.0

Table 4.7: Flue analysis by volume

4.2.1.3.1 Heat Balance Calculations

Evaporation temperature of moisture in fuel and air = 100 °F because of low vapor pressure in the furnace path. Specific heat to be used:

- a) water vapor in flue gas = 0.47 Btu/lb/°F
- b) water = 1.00 Btu/lb/°F
- c) flue gas = 0.24 Btu/lb/°F

a) **Heat loss due to water in fuel, H_w**

Enthalpy of steam at 100 °F = 1105.2 Btu/lb

Heat loss due to water vapor = $0.47(t_g - 100)$

Heat gained by water from 32 °F = $1(t_f - 32)$

Temperature of flue gas leaving boiler, $t_g = 452$ °F

Temperature of fuel and air entering boiler, $t_f = 74$ °F

Weight of moisture per lb fuel fired, $W_m = 8\%$

$$H_w = W_m [1105.2 + 0.47(t_g - 100) - (t_f - 32)]$$

$$H_w = W_m [1090.2 + 0.47t_g - t_f]$$

$$H_w = 0.08 [1090.2 + 0.47(452) - 74]$$

$$H_w = 98.3 \text{ Btu/lb fuel fired}$$

b) **Heat loss due to moisture in combustion air, H_a**

$W_v =$ (weight of water vapor required to saturate 1 lb dry air at 74 °F) x (relative humidity) x (weight of dry air used per lb fuel)

Relative humidity = 0.7

$$W_v = 0.7 \times 0.01815 \times 10.15$$

$$W_v = 0.129 \text{ (detailed calculation of } W_v \text{ is shown in Appendix 4.2)}$$

$$H_a = W_v (0.47(t_g - t_f))$$

$$H_a = 0.129 \times 0.47(452 - 74)$$

$$H_a = 22.9 \text{ Btu/lb fuel fired}$$

c) **Heat loss due to hydrogen in fuel forming water vapor, H_h**

$$H_h = 9W_h[1090.2 + 0.47t_g - t_f]$$

$$H_h = 9 \times 0.04[1090.2 + 0.47(452) - 74]$$

$$H_h = 442 \text{ Btu/lb fuel}$$

d) **Heat loss due to dry chimney gas, H_{cg}**

$$H_{cg} = W_{dg}(C_p)(t_g - t_f)$$

$$W_{dg} = 10.493 \text{ lb}$$

$$H_{cg} = 10.493 \times 0.24(452-74)$$

$$H_{cg} = 951.9 \text{ Btu/lb fuel fired}$$

e) **Heat loss due to unburned combustible, H_u**

This type of loss occurred caused by insufficient air or poor fuel-air mixing.

Using percentage from flue gas analysis:

$$H_u = [\text{CO}/(\text{CO} + \text{CO}_2)] \times 10160 \times C_1$$

$$C_1 = 0.5822 \text{ lb}$$

$$H_u = [1/(1 + 13)] \times 10160 \times 0.5822$$

$$H_u = 422.5 \text{ lb}$$

f) **Heat loss due to unconsumed combustible in ash**

$$H_r = [14600 (W_r C_r)] / W_f$$

$$H_r = 14600 (420 \times 0.18) / 2000$$

$$H_r = 551.9 \text{ Btu/lb fuel fired}$$

g) **Miscellaneous losses, H_m**

$$H_m = 0.0411 (11800)$$

$$H_m = 485 \text{ Btu/lb fuel fired}$$

Summation of all losses = 2974.5 Btu/lb fuel fired

Output of boiler = 11800 – 2974.5 = 8825.5 Btu/lb fuel fired

$$\text{Efficiency} = \frac{\text{Input} - \text{Losses}}{\text{Input}} \times 100$$

$$\text{Efficiency} = \frac{11800 - 2974.5}{11800} \times 100$$

$$\text{Efficiency} = 74.8 \%$$

4.2.2 Steam Flow Measuring System

4.2.2.1 Calculation of Flow Measurement

4.2.2.1.1 Observation Log Sheet

Steam orifice: differential pressure (mbar)	172.5
Steam orifice: differential pressure (°C)	215.0
Steam orifice: differential pressure (bar.g)	5.5
Steam Line : dryness fraction of steam	superheated

4.2.2.1.2 Derived Results

Steam orifice: specific volume (m ³ /kg)	0.3379
Steam orifice: steam density (kg/m ³)	2.9598
Steam orifice: steam mass flow rate (kg/hr)	70.2700

4.2.2.1.3 Flow Measurement

Diameter of orifice is 11mm.

172.5 mbar differential pressure at 5.5 gauge pressure on 11mm orifice gives a flow of 70.27 kg/hr for steam of dryness fraction, $q = 1$. Since steam temperature is 215 °C, therefore the steam is superheated.

With a dryness fraction $q = 0.9$, the flow would be

$$\text{New Flow} = 70.27 \times K_q$$

From figure 4.3 (Refer to Appendix 4.3), for $q = 0.9$, $K_q = 1.054$

$$\text{New Flow} = 70.27 \times 1.054 = 74.07 \text{ kg/hr}$$

When dryness fraction $q = 0.96$, the new flow would be;

From figure 4.3 (Refer to Appendix 4.3), for $q = 0.96$, $K_q = 1.02$

$$\text{New Flow} = 70.27 \times 1.02 = 71.68 \text{ kg/hr}$$

4.2.3 Separating and Throttling Calorimeter

4.2.3.1 Calculation of dryness fraction

The dryness fraction of wet steam may also be determined experimentally using a separating and throttling calorimeter. Here, a separator is used to first separate most of the water from the steam and then the steam is throttled so it becomes superheated. By measuring the original pressure of the steam, the pressure and temperature after throttling as well as the amount of the water collected in the separator, the initial dryness fraction can be determined.

4.2.3.1.1 Data Available

Sample observation log sheet

Parameter	1	2	3	4	5	6	Average
Steam pressure in main (bar)	8.2	8.0	8.3	8.4	8.5	8.1	8.25
Steam pressure after throttling (mmHg)	37	37	37	40	40	40	38.5
Temperature after throttling (°C)	136	136	136	137	138	138	136.8

Table 4.8: Observation log sheet

Quantity of separated water, $W_s = 110.85$ cc

Quantity of condensate, $W_t = 2250$ cc

Atmospheric pressure = 762 mmHg

Difference in levels due to water in mercury manometer = 7 mm

Steam pressure after throttling = $38.5 - 7 = 31.5$ mmHg

Absolute pressure after throttling = $31.5 + 762 = 793.5$ mmHg

$$P_2 = (793.5 / 750) = 1.085 \text{ bar}$$

Absolute pressure in steam main $P_1 = 8.25 + 1.00 = 9.25$ bar

Using steam table and interpolating;

$$\begin{aligned} h_{f1} \text{ at } 9.25 \text{ bar} &= 748 \text{ kJ/kg} \\ h_{fg1} \text{ at } 9.25 \text{ bar} &= 2027 \text{ kJ/kg} \\ h_{g2} \text{ at } 1.085 \text{ bar} &= 2678 \text{ kJ/kg} \\ c_p \text{ for superheated steam} &= 1.89 \text{ kJ/kg } ^\circ\text{C} \\ t_{s2} \text{ at } 1.085 \text{ bar} &= 101 \text{ } ^\circ\text{C} \end{aligned}$$

Dryness fraction at throttling calorimeter X_t

$$\begin{aligned} X_t &= [h_{g2} + c_p (t_2 - t_{s2}) - h_{f1}] / h_{fg1} \\ &= [2678 + 1.89(136.8 - 101) - 748] / 2027 \\ &= 0.986 \end{aligned}$$

Dryness fraction at separating calorimeter

$$\begin{aligned} X_s &= 2250 / (2250 + 110.85) \\ &= 0.953 \end{aligned}$$

Combined dryness fraction

$$\begin{aligned} X &= X_t \cdot X_s \\ &= 0.986 (0.953) \\ &= 0.940 \end{aligned}$$

Thus, it can be conclude that the quantity of dry steam is 94% in the sample.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

Base from the review and calculation conducted for these three sections of experiments, it shows that the data available can be used as references to the experiments. But due to limited source of data and information, the calculation can not be made as detail as possible. The experimental work should be conducted to give the author better understanding on the experiments rather than using the limited data and source of information available only. The understanding regarding to the experiments considered also not good enough and this situation affected the results obtained from the calculation and review.

The problem occurred to the steam power plant might be unexpected, but it affected a lot to the author project. The author had experienced lot of time losses to find the data this reflect the outcome of the project. In term of personal experience, the author had learned that there is nothing happened in this life as expected and this experience reflect to the author when the author face this type of challenge in the future, especially in working field. Thus, this kind of exposure to this kind of problem help to make the author mentally prepared to face this challenge.

The section of experiments here are experiments using separating and throttling calorimeter, experiments using additional boiler instrumentation and experiment of calculating steam flow measuring system. All these experiments are good enough to give exposure to the students as an introduction to the boiler system. When the students deal with the boiler during the industrial internship program, it will help a lot and save a lot of time to understand the principle of boiler since nowadays more industrials are likely to use boiler system in plant.

5.2 Recommendations

The author had experienced a well exposure and knowledge throughout the 2 semesters of conducting the project. Although the steam power plant can not be operated as expected, the exposure to this type of engineering equipment had gave the author better understanding compared to before.

Here, the author recommends that the steam power plant experiments should be continued by other students so that the better experimental procedure and manual for the steam power plant can be prepared. Things will become easier when the steam power plant can be operates because the main thing of this project is the data. Without the data, there is nothing the student can do, especially to conduct the calculations and the discussions that reflect the conclusions of the experiments. The project will only stuck at the literature review and methodology of the project only.

UTP also should have a technician that qualified to run the boiler, meaning that UTP should have a technician with a boilerman certificate. This is to avoid problem raise in term of regulation since this is a requirement by Department of Occupational, Safety and Health (DOSH). There is no point having a boiler without a boilerman because the boiler can not be operates without the boilerman since this situation is against the law. The investment to install the steam power plant that cost a lot of money will do no nothing and the students also get nothing if the situation that the author had experienced will continue without any action taken.

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APPENDICES

APPENDIX 2.1: TYPICAL FIRE TUBE BOILER (EXTERNALLY FIRED)

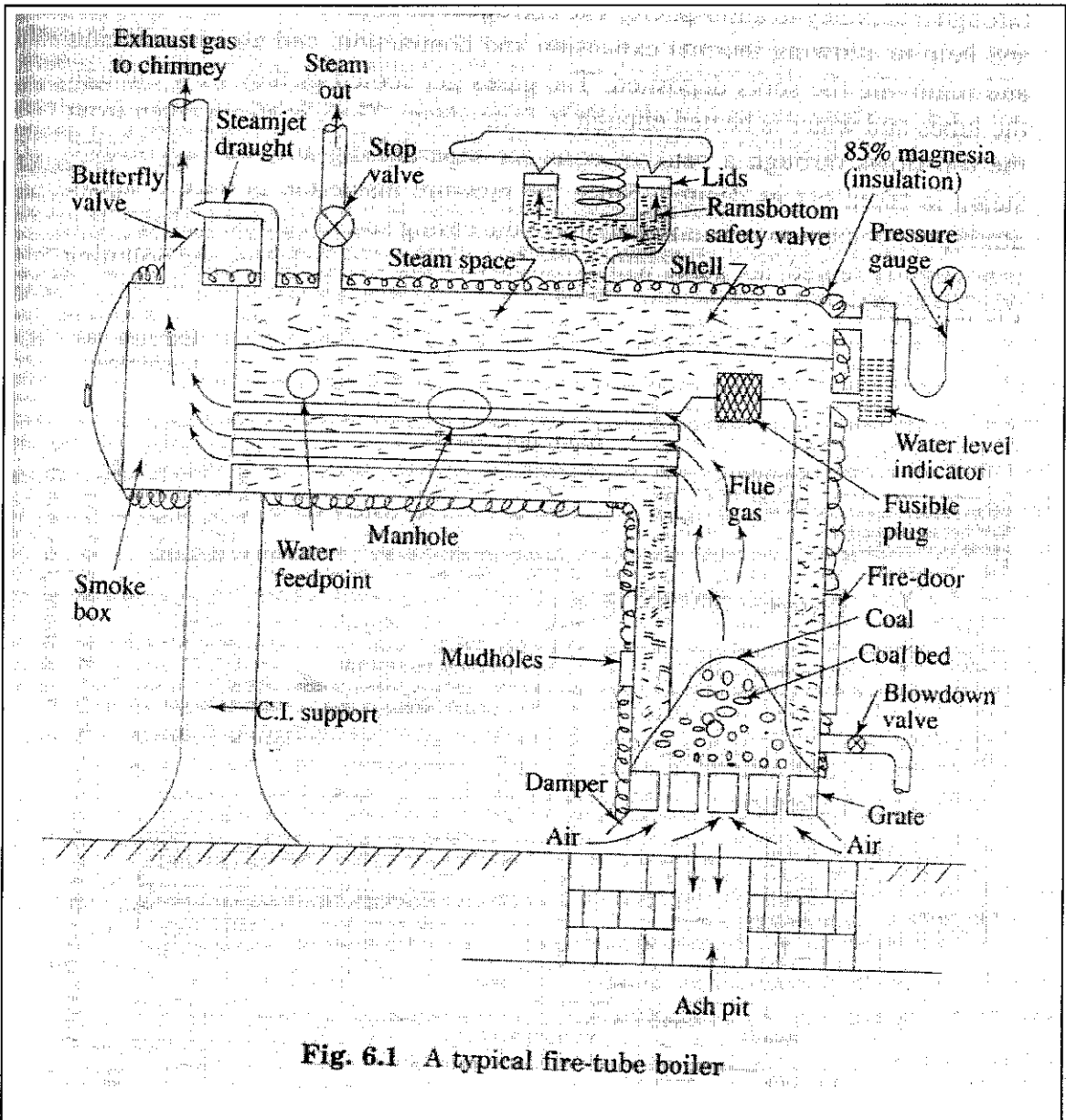


Fig. 6.1 A typical fire-tube boiler

APPENDIX 2.2: OIL FIRED TUBE PACKAGE BOILER (INTERNALLY FIRED)

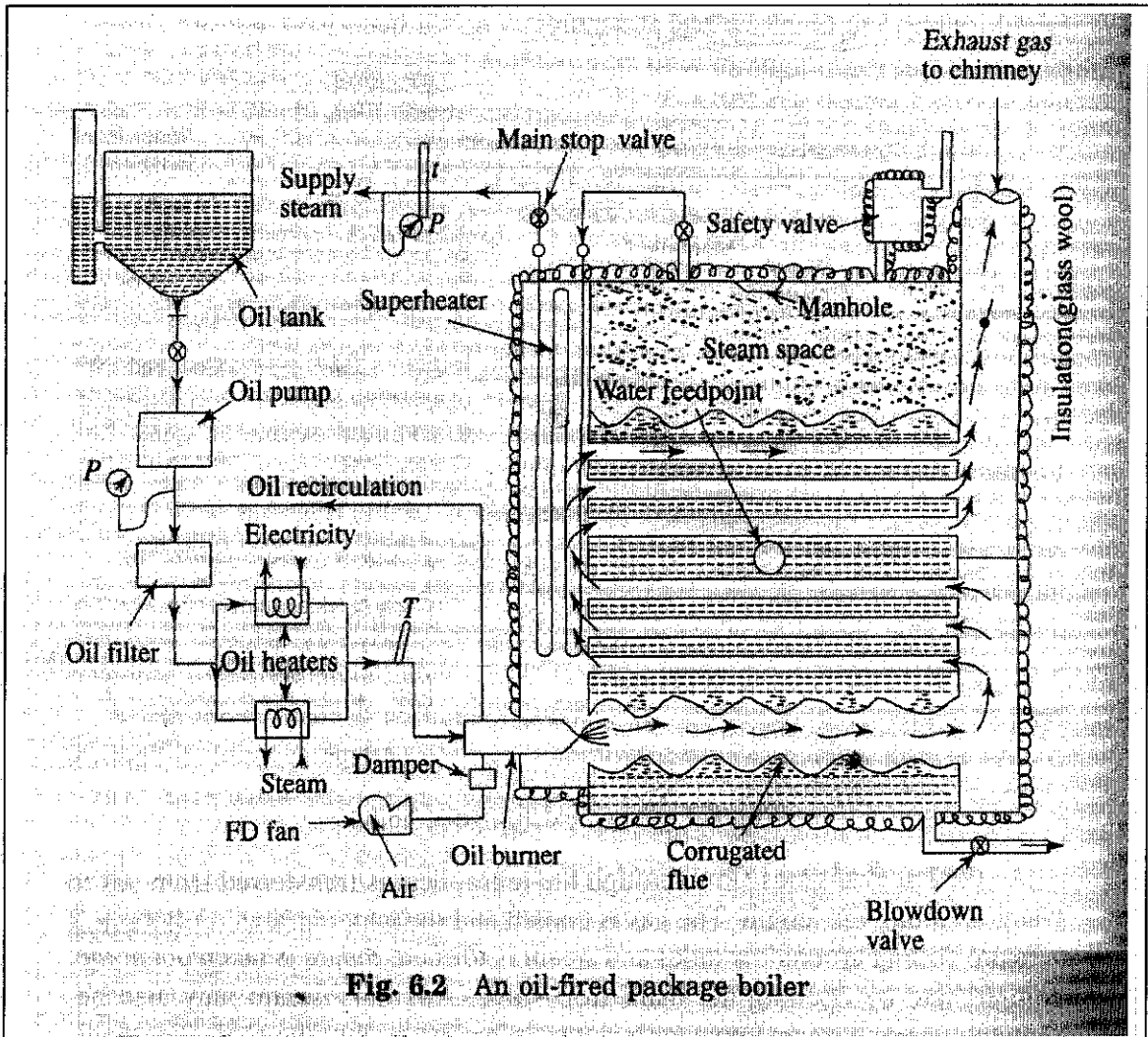
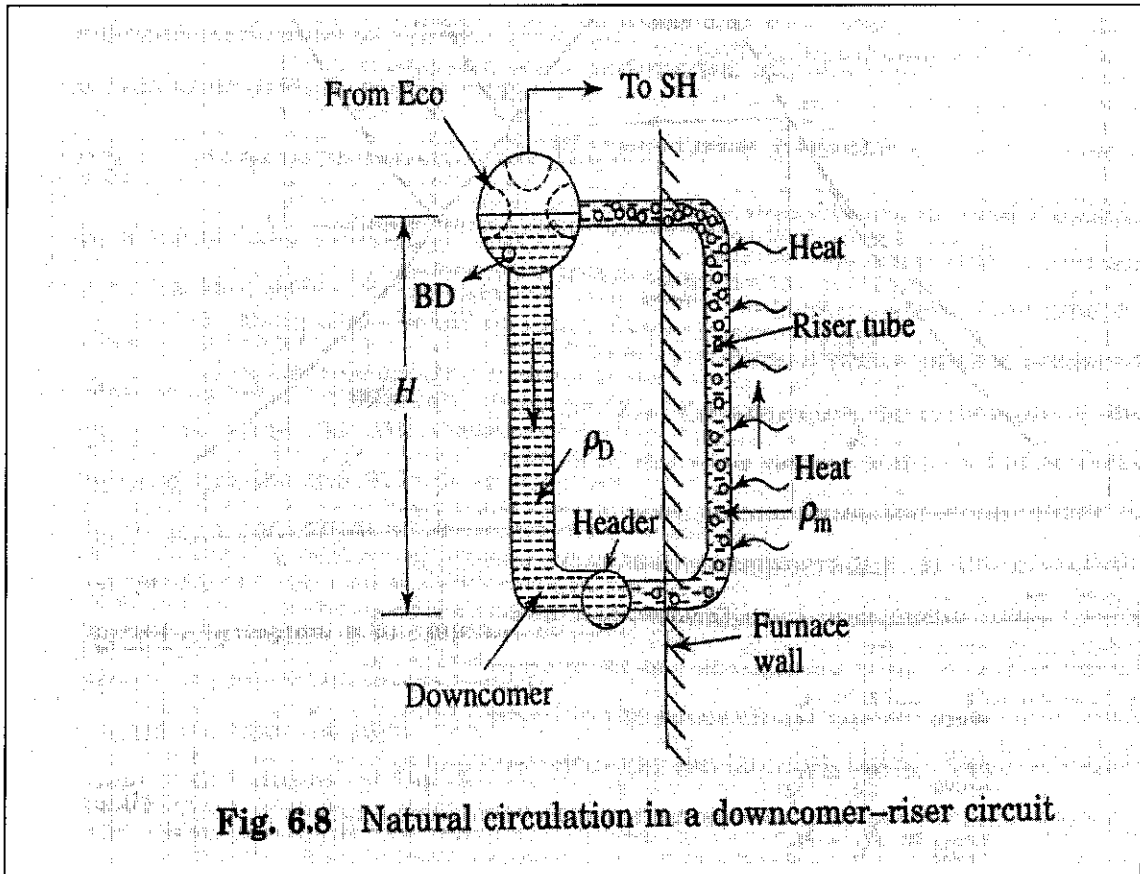
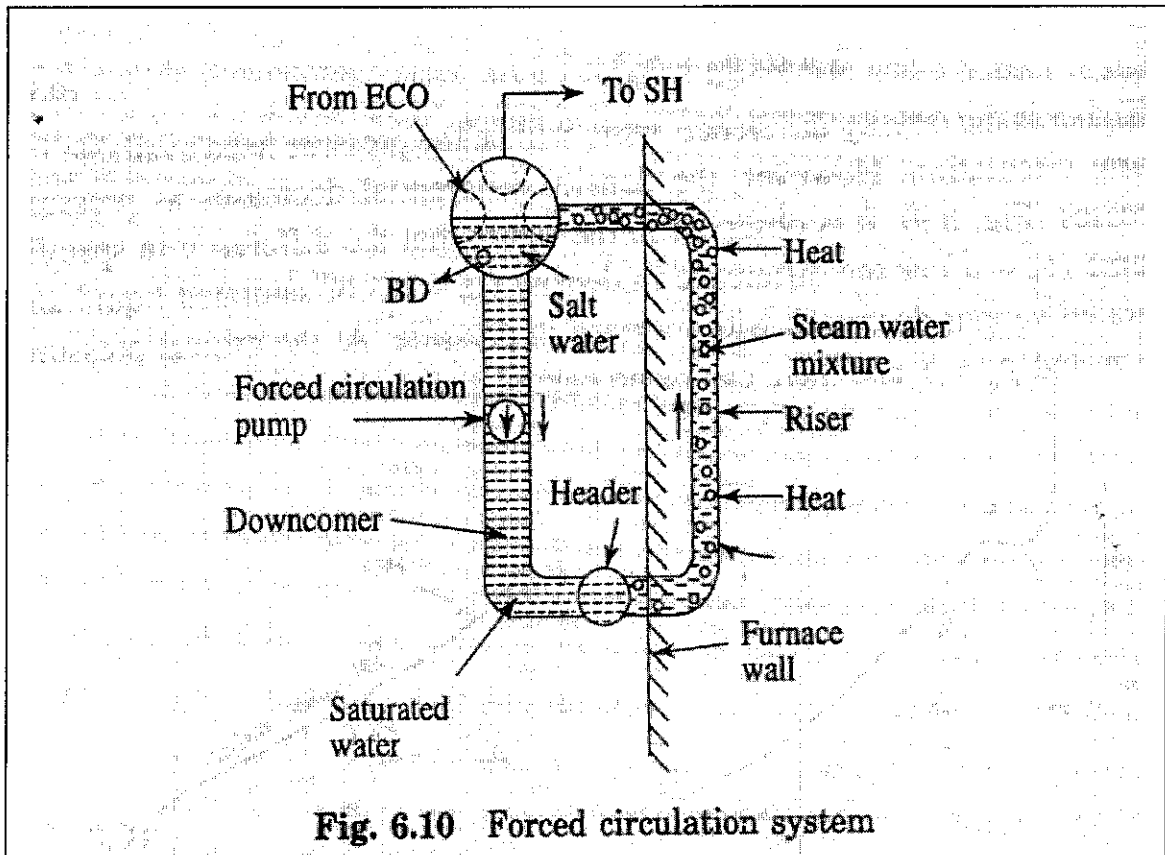


Fig. 6.2 An oil-fired package boiler

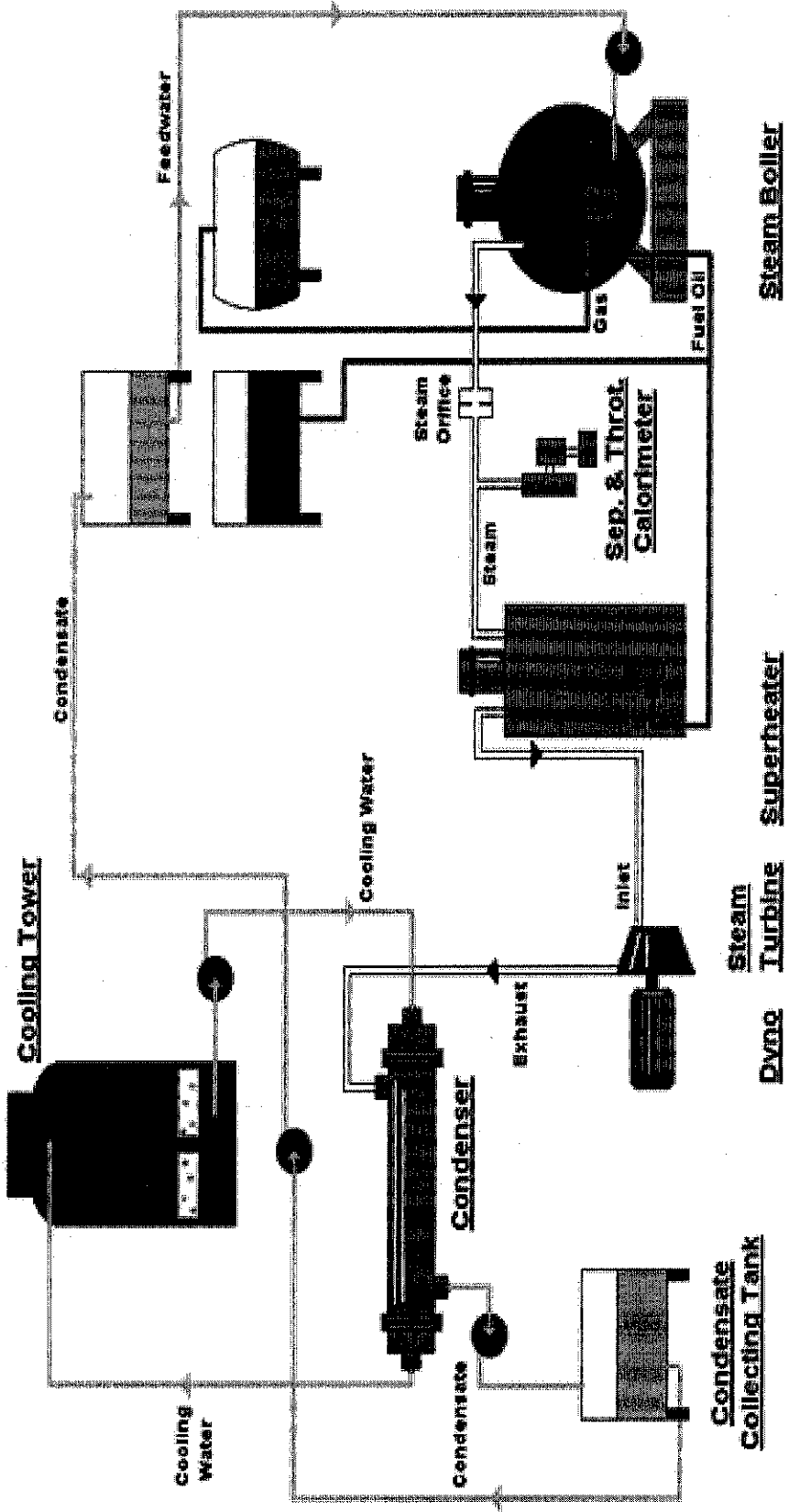
APPENDIX 2.3: NATURAL CIRCULATION



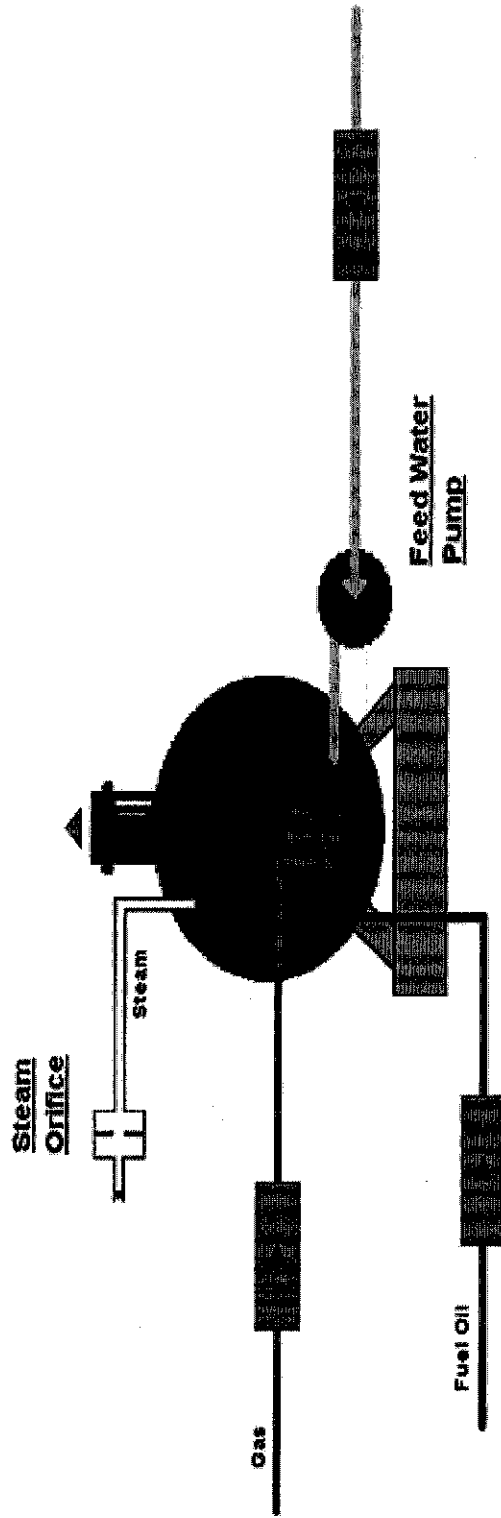
APPENDIX 2.4: FORCED CIRCULATION



APPENDIX 3.1: LAYOUT OF STEAM POWER PLANT



APPENDIX 3.2: BOILER DIAGRAM



APPENDIX 3.3: SAMPLE OF RESULT SHEET USED FOR EXPERIMENT USING ADDITIONAL BOILER INSTRUMENTATION

Time	Fuel Reading	Feed water reading	Temperature of feedwater	Temperature of flue gases
0				
10				
20				
30				
40				
50				
60				
70				
80				
90				

Table 3.1: Result sheet

APPENDIX 3.4: OBSERVATION LOG SHEET FOR SEPARATING AND THROTTLING CALORIMETER

Parameter	Observation No.						
	1	2	3	4	5	6	Avg
Observed steam pressure in main (bar gauge)							
Observed steam pressure after throttling (mmHg)							
Temperature after throttling (t_2 °C)							
Quantity of separated water (w_s cc)							
Quantity of condensate (w_s cc)							

Barometric pressure =

Table 3.3: Result sheet for separating and throttling calorimeter

APPENDIX 4.2: CALCULATION INVOLVED IN BOILER EFFICIENCY

Calculation of weight of carbon, C_1

$$C_1 = \frac{W_f C_f - W_r C_r}{W_f (100)}$$

Weight of fuel fired, $W_f = 2000$ lb

Percent carbon from ultimate analysis, $C_f = 62$ %

Weight of ash, $W_r = 420$ lb

Percent carbon content of ash from ultimate analysis = 18 %

Substituting,

$$C_1 = \frac{2000(62) - 420(18)}{2000(100)}$$

$$C_1 = 0.5822 \text{ lb}$$

Calculation of the weight of dry chimney gases, W_{dg}

$$W_{dg} = [4CO_2 + O_2 + 700] / [3(CO_2 + CO) \times [(W_f C_f - W_r C_r) / W_f (100)]]$$

Substituting:

$$W_{dg} = [4(13) + 5 + 700] / [3(13 + 1) \times (0.5822)]$$

$$W_{dg} = 10.493 \text{ lb/lb fuel}$$

$$\text{The weight of dry air, } W_{da} = W_{dg} - C_1 + 8[H - O/8]$$

Substituting:

$$W_{da} = 10.493 - 0.5822 + 8[0.04 - 0.08/8]$$

$$W_{da} = 10.15 \text{ lb/lb fuel}$$

APPENDIX 4.3: CORRECTION FOR DRYNESS FACTOR

