การวิเคราะห์ประสิทธิภาพการเผาไหม้เชื้อเพลิงออกซีฟูเอลแบบฟลูอิดไดเบดหมุนวนสำหรับ
โรงไฟฟ้าถ่านหิน

นางสาวสมฤทัย มะลิทอง

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INVESTIGATING THE PERFORMANCE OF CIRCULATING FLUIDIZED BED OXY-FUEL COMBUSTION IN A COAL FIRED POWER PLANT

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A Thesis Submitted in Partial Fulfillment of the Requirements
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สมฤทัย มะลิทอง : การวิเคราะห์ประสิทธิภาพการเผาไหม้เชื้อเพลิงออกซีฟูเอลแบบฟลูอิดไดเบดหมุนวนสำหรับโรงไฟฟ้าถ่านหิน (INVESTIGATING THE PERFORMANCE OF CIRCULATING FLUIDIZED BED OXY-FUEL COMBUSTION IN A COAL FIRED POWER PLANT) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร.อมรชัย อาภรณ์วิชานพ, 139 หน้า.

ในงานวิจัยนี้กระบวนการเผาไหม้เชื้อเพลิงออกซีฟูเอลสำหรับโรงไฟฟ้าถ่านหิน โดยหลักการเทอร์โมไดนามิกส์ได้ถูกนำมาใช้เพื่อประเมินผลสภาวะในการดำเนินการของโรงไฟฟ้าถ่านหิน ในแง่ของประสิทธิภาพของหม้อไอน้ำ ประสิทธิภาพของเครื่องกันหันไอน้ำ และกำลังงานสุทธิ แบบจำลองในงานวิจัยนี้ได้ถูกพัฒนาด้วยโปรแกรมสำเร็จรูปเกทไซเคิล โดยตรวจสอบความถูกต้องของแบบจำลอง ด้วยการเปรียบเทียบผลการจำลองกับสภาวะการดำเนินการของโรงไฟฟ้าพบว่า ค่าความผิดพลาดสูงสุดอยู่ที่ 1.56 เปอร์เซ็น การเผาไหม้เชื้อเพลิงออกซีฟูเอลที่ความเข้มข้นของออกซีเจน 0.95% และอัตราส่วนการนำก๊าซเสียกลับมาใช้ที่ 0.7 พบว่า กำลังงานผลิตเพิ่มขึ้นจาก 131.80 เป็น 135.11 เมกกะวัตต์ และการสูญเสียพลังงานในก๊าซเสียลดลงจาก 27.5 เป็น 13.8 เมกกะจูลต่อวินาที สำหรับสภาวะการดำเนินการสำหรับการเผาไหม้เชื้อเพลิงออกซีฟูเอล อัตราส่วนการนำก๊าซเสียกลับมาใช้เพิ่มขึ้น ส่งผลให้งานสุทธิเพิ่มขึ้น ความเข้มข้นของออกซีเจนเพิ่มขึ้น ประสิทธิภาพของหม้อไอน้ำเพิ่มขึ้น การศึกษาการนำความร้อนจากก๊าซเสียกลับมาใช้ โดยการออกแบบเครื่องแลกเปลี่ยนความร้อน ระหว่างน้ำที่ส่งไปที่หม้อไอน้ำ พบว่า ตำแหน่งการติดตั้งเครื่องแลกเปลี่ยนความร้อนที่ใกล้หม้อไอน้ำ เพิ่มประสิทธิภาพของหม้อไอน้ำ ผลการจำลองพบว่าสภาวะที่เหมาะในกระบวนการเผาไหม้เชื้อเพลิงออกซีฟูเอลสำหรับโรงไฟฟ้าถ่านหิน ประสิทธิของหม้อต้มไอน้ำ มีค่าระหว่าง 86.20% ถึง 85.55% เมื่อมีการประยุกต์ใช้อัตราส่วนการนำก๊าซเสียกลับมาใช้ระหว่าง 0.71 ถึง 0.75 ที่ออกซิเจนบริสุทธิ์ความเข้มข้นร้อยละ 95 โดยมวล

ภาควิชา วิศวกรรมเคมี

สาขาวิชา วิศวกรรมเคมี

ปีการศึกษา 2558

ลายมือชื่อนิสิต ....

ลายมือชื่อ อ.ที่ปรึกษาหลัก ....

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SOMRUETHAI MALITHONG: INVESTIGATING THE PERFORMANCE OF CIRCULATING FLUIDIZED BED OXY-FUEL COMBUSTION IN A COAL FIRED POWER PLANT. ADVISOR: ASST. PROF. DRAMORNCHAI ARPORNWICHANOP, D.Eng., 139 pp.

This research presents a study on the oxy-fuel combustion of a coal-fired power plant. Thermodynamic approach is applied to evaluate the impact of operating parameters on the power plant in terms of the boiler efficiency, the turbine thermal efficiency and the net power capacity of the power plant. The GateCycle application used for design and performance evaluation of thermal power plant systems at both design and off-design condition. The model validation is based on the air-combustion power plant, the result of GateCycle and the design data at the boiler maximum continuous rating (BMCR) is comparable with a maximum error of approximately 1.56%. The gross power generation of the oxy-fuel combustion at 0.7 RFG ratio and oxygen concentration 0.95%mass compare with conventional combustion increases from 131.80MW to 135.11MW and energy loss of flue gas decreases from 27.5MJ/s to 13.8MJ/s. The operation condition of oxy-fuel combustion, the higher recycled flue gas ratio increases the net power generation, turbine efficiency and increases the concentration of CO_2 in the flue gas. The boiler efficiency is increased by increasing the oxygen concentration. The heat recovery from recycled flue gas is investigated by integrating the heat exchanger before the feed water heater unit. The position of heat exchanger locates approach the boiler can be improve the boiler efficiency. The results are used as data to investigate the performance of the coal-fired power plant. The results of model show that the boiler efficiency is 86.20% to 85.55% when the recycled flue gas ratio at 0.71 to 0.75 and oxygen concentration at 0.95% mass is applied.

Department:	Chemical Engineering	Student's Signature	....
Field of Study:	Chemical Engineering	Advisor's Signature	....
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NOMENCLATURES

$\mathbf{W_i}$	mass flow rate of the substance i, such as O2, N2, CO2 or H2O
$\mathbf{W_{gas}}$	mass flow rate of the gas mixture
$\mathbf{X_i}$	mole fraction (or volume fraction for a gas) of the substance i in the gas mixture
$\mathbf{M_i}$	molecular weight of the substance i
$\mathbf{M_{gas}}$	molecular weight of the gas mixture
$\mathbf{X_{O2flue}}$	mole fraction (volume) of oxygen at the flue gas exit of furnace
$\mathbf{X_{O2flue}}$	mole fraction (volume) of oxygen at air inlet to the furnace
$\mathbf{M_{gasflue}}$	molecular weight of the combustion gas at the flue gas exit
$\mathbf{M_{gasin}}$	molecular weight of the oxygen in the air inlet to the furnace
$\mathbf{W_{fuel}}$	mass flow rate of the fuel
$\mathbf{W_{gasflue}}$	mass flow rate of gas mixture at the flue gas exit of furnace
$\mathbf{W_{gasin}}$	mass flow rate of the oxygen in the air inlet to the furnace
$\mathbf{C_b}$	mass of carbon burned per unit fuel mass

$\%H$	mass fraction of hydrogen in the fuel, except the hydrogen in the moisture in the fuel
$\%H_2O$	mass fraction of moisture in the fuel
$\%S$	fraction of sulfur in the fuel
$\%O$	mass fraction of oxygen in the fuel
$(\%C)_{fuel}$	mass fraction of carbon in the fuel
$(\%C)_{ash}$	mass fraction of unburned carbon in the ash
$(\%Ash)_{fuel}$	mass fraction of ash in the fuel .
$h_{gasflue}$	enthalpy of the gas in the flue gas
$W_{gasflue}$	gas flow rate of flue gas
T_{gasin}	temperature of the gas at the air inlet
T_{gasref}	reference gas temperature where the enthalpy equal to zero
h_{ash}	enthalpy of the ash outlet the furnace
W_{ash}	mass flow rate of the ash outlet the furnace
LHV	lower heating value of the fuel
$\%C_{ash}$	mass fraction of carbon in the ash (pounds of carbon per pound of ash)

$\mathbf{hc}$	heating value of carbon in the ash
$\mathbf{Q_{wall}}$	heat transfer rate to the furnace walls
$\mathbf{Q_{SH}}$	heat transfer rate to the main steam superheater section in the furnace
$\mathbf{Q_{RH}}$	heat transfer rate to the reheat steam superheater section in the furnace
$\mathbf{Q_{rad}}$	radiation heat transfer rate to the environment
$\mathbf{h}$	enthalpy of the water/steam at the inlet and/or outlets of the heat exchangers
$\mathbf{w}$	mass flow rate of the water/steam at the inlet and/or outlets of the heat exchangers
$\mathbf{C_{Pi}}$	specific heat of the ash leaving the boiler at position i
$\mathbf{F_{i}}$	ash mass fraction of the ash leaving the boiler at position i
$\mathbf{T_{i}}$	temperature of the ash leaving the boiler at position i
$\mathbf{T_{ref}}$	is the reference temperature at the enthalpy equals zero
$\mathbf{C_{Pi}}$	specific heat of the substance i
$\mathbf{C_{Pgas}}$	specific heat of the gas mixture

$\mathbf{X_i}$	mole fraction of the substance I in the gas mixture
$\mathbf{M_i}$	molecular weight of substance i
$\mathbf{M_{gas}}$	molecular weight of the gas mixture
w	mass flow rate, with the below subscripts:
sh	mains steam at the superheater exit,
rh	reheat steam at the exit of the reheat superheater
feed	inlet feed water which include water in the desuperheating sprays
crh	cold reheat steam input to the boiler
air	inlet air to the boiler
fuel	fuel input to the boiler
h	enthalpy (BTU/lbm or kJ/kg)
LHV	lower heating value of the fuel
$\mathbf{W_{fan}}$	is the power input to the boiler fans and auxiliaries load.
Losses	total energy outflows other than use of steam per unit fuel flow
HHV	fuel higher heating value (BTU/lbm) or (kj/kg)

Credits energy that flows into the boiler other than fuel energy per unit fuel flow.

$L_{fluegas}$ energy lost in the flue gas per unit fuel flow

L_{ash} energy lost in the ash per unit fuel flow

$L_{radiation}$ energy lost because the heat transfer from the boiler to the environmental

Theoretical air mass of air per mass of fuel required for stoichiometric combustion

XO_2air volume fraction of oxygen in the inlet air (or gas mixture)

M_{O2} molecular weight of oxygen that equal to 32

M_{air} molecular weight of inlet air that equal to 28.97 for standard air or of the inlet gas mixture that contain oxygen

M_{H2} molecular weight of hydrogen that equal to 2

M_C molecular weight of oxygen that equal to 12

%C mass fraction of carbon in the fuel

%H mass fraction of hydrogen in the fuel

%S mass fraction of sulfur in the fuel

%O mass fraction of oxygen in the fuel

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%C mass fraction of carbon in the fuel

%H mass fraction of hydrogen in the fuel

%S mass fraction of sulfur in the fuel

%O mass fraction of oxygen in the fuel

Excess air additional airflow added to the boiler in addition to the theoretical air

X_{O2flue} volume fraction of oxygen in the flue gas

X_{O2air} volume fraction of oxygen in the ambient air

h enthalpy (BTU/lbm or kJ/kg)

H heating value of gas when combusted (BTU/lbm or kJ/kg)

L_{flue} gas energy loss per unit fuel flow associated with the flue gas

W_{flue} mass flow rate of the flue gas

W_{fuel} mass flow rate of the fuel

H_{flue} enthalpy of the fuel (BTU/lbm or kJ/kg)

$\frac{w_{ash}}{w_{fuel}}$ mass of ash generated per unit mass of fuel

$(\%C)_{ash}$ mass of carbon per unit mass of ash produced

H_{ash} enthalpy of the ash, equal to the specific heat multiplied by the temperature

H_C heating value of carbon in the ash

h_{in} steam enthalpy at the inlet to the steam turbine

h_{out} steam enthalpy at the outlet to the steam turbine

$h_{out,ideal}$ isentropic (ideal) steam enthalpy at the outlet of the steam turbine

W_{fin} mass inlet flow rate of feed water to the feedwater heater

W_{fout} mass outlet flow rate of feed water to the feedwater heater

$\mathbf{h_{f,in}}$	enthalpy of the feedwater at the inlet flow port
$\mathbf{h_{f,out}}$	enthalpy of the feedwater at the outlet flow port
Q_{fwh}	heat transfer rate (duty) from the steam-side to the water side
$\mathbf{W_{s,in}}$	mass inlet flow rate of extraction steam into the feedwater heater
$\mathbf{W_{d,in}}$	mass inlet flow rate of drain water from a higher pressure feedwater heater
$\mathbf{W_{d,out}}$	mass outlet rate of drain water out of the feedwater heater
$\mathbf{h_{s,in}}$	enthalpy of the extraction steam at the inlet flow port
$\mathbf{h_{d,in}}$	enthalpy of the inlet drain water
$\mathbf{h_{d,out}}$	enthalpy of the outlet drain water

Chapter I
Introduction

1.1 Background and motivation

Coal is an important energy source that is used widely in many industries such as petrochemical, transportation and power generation. Some of the products derived from coal can be useful but the down side is that when it is burnt it produces emissions that have an adverse effect on the environment. There is a particular focus on carbon dioxide which attributes largely to the greenhouse effect. Therefore, there is a huge effort to find ways of reducing CO2 emissions released from the combustion of fossil fuels. Nowadays, there are many potential technologies that can reduce CO2 emissions, for example carbon dioxide capture and storage (CCS) which can be retrofitted to existing power plants. Much of the process of the CCS for power plant produces an almost pure stream of CO2 using pure oxygen O2 as the combustion gas. Currently, CCS consists of 3 technologies of which are post-combustion capture. This technology uses a chemical solvent such as monoethanolamine (MEA) or ammonia to scrub CO2 out of the flue gas which is then sent to the stripper or regeneration tower where used heat is used to separate CO2 from the solvent. This post-combustion technology in coal-fired power plants is not widely used because the nitrogen in the flue gas is around 70%, with little CO2 and the equipment in this process is large. The pre-combustion is technology is where coal is gasified with oxygen and steam at high temperature and high pressure to produce syngas. Syngas consists of carbon-monoxide (CO) and hydrogen (H2) Carbon-monoxide is used as a reactant in water which can convert CO and H2O to H2 and CO2. A sorbent is used to separate the

CO2. The syngas can combust in the gas turbine to generate power. The coal gasification power plant is known as the integrated gasification combined cycle (IGCC) and is sometimes referred to as a clean coal technology because it can recover up to 99.5% of sulfur in the coal. The IGCC has a higher thermal efficiency and lower CO2 emissions rates. Power plant retrofits using a gasified system have a high cost because of its complexity. Research into using of IGCC with low rank coal is the subject of further research.

The oxy-fuel combustion for CO2 capture uses oxygen instead of air for combustion. Nitrogen will be eliminated from the combustion air. The concentration of CO2 and water in the flue gas are separated when water is condensed. The oxy-fuel combustion and the recycled flue gas can be used for reducing emissions of greenhouse gases in existing coal fired power plant. The recycled flue gas is fed back to the bed region of boiler to reduce the highly oxidized of pure oxygen which has an effect on the material of boiler, control the temperature in the furnace and to maintaining an adequate heat transfer in the unit.

Typically, oxy-fuel combustion is investigated using heat and mass balance and the experiment. Many associations and researcher analyzed the oxy-fuel combustion IshikawajimaHarima Heavy industry and Electric Development operation designed a test for power plant under the condition that flue gas with a CO_2 concentration of 90% or more would be directly disposed of underground. The ALSTOM Company evaluated the effect of adding the utilize to capture more than 90% of the CO2 and performed the inclusive study evaluating the technical and economic feasibility of three alternate CO2 capture technologies applied to an existing coal-fired electric power plant. The Foster Wheeler team presented the 475MW of supercritical coal-fired power plant. The power plant system was optimized to saving the heat rate of the power plant and CO2 sequestration unit. The Vattenfall in Sweden and Chalmers University presented the process of an O2/CO2 plant by using the commercial data for the important components in the process, and proposed that O2/CO2 combustion is a practical and the future choice for CO2 reductions in the power generation by retrofit from the existing plants and components. The CANMET in Canada proposed the techno-economic comparison of the performance of the two solutions: scrubbing by MEA and recycle combustion of O2/CO2. The Aspen plus was used to compare the commercial process simulation. The Greenfield power plant was applied the oxy-fuel combustion for CO2 capture with the lignite-fired power plant. The Greenfield power plant proposed that indicates for the benefit of heat that should be if not useless will be raised. The Korea power plant is evaluated the performance of the comercial power plant 100MWe that retrofited the oxy-fuel combustion for demostration. This process is based on the design operating condition and the suitable assumption. The performance was concluded based on the heat and mass balance of the power plant. The result is proposed the efficiency and exergy of the retrofitting plant.

All of the above references to, Oxy-fuel combustion have challenged the energy sector to seek solutions for a safer environment. The investigation into Oxy-fuel combustion use of the Gate-cycle to verify and import the retrofitting oxy-fuel system and recycled flue gas into existing coal-fired power plant and its effect on operation of existing power plant. The coal-fired power plant has the individual characteristic of each plant then the investigations will examine the deviations from the design condition and any adverse effect on the steam path.

1.2 Research Objectives

1. To compare the performance and emission of the oxy-fuel and conventional combustion in the coal-fired power plant

2. To investigate effects of operating parameters on the performance of the oxy-fuel combustion in the coal-fired power plant

3. To design heat exchanger of the recycled flue gas and feed water heater system

4. To identify optimal operating parameters of the oxy-fuel combustion

1.3 Scopes of work

1. Modeling of the coal fired power plant retrofitted with oxy-fuel combustion with GateCycle software.

2. To investigate the optimal operating conditions of the coal-fired power plant such as, adiabatic flame temperature in the furnace, inlet-outlet turbine temperatures, amount, temperature and energy loss of flue gas

3. Analysis of the performance such as the boiler efficiency, gross power generation, net power generation, steam turbine efficiency of the coal-fired power plant

4. Investigate the boiler efficiency, power generation integrated recycle flue gas heat recovery by the heat exchanger integration.

CHAPTER II

Literature Review

2.1 Carbon Capture and Storage in the power plant

Carbon dioxide emissions produced by the combustion of coal is linked to the greenhouse effect and global climate change. One way of reducing this form of greenhouse gas emissions is the, capture and storage of CO_2. Current technology of Carbon capture and storage focuses on the following: pre-combustion capture, post-combustion capture, and oxy-fuel combustion. The technology of CO_2 capture and storage has a number of detriments,. CO_2 capture and storage will result in a reduction of the efficiency of the power plant and thus increasing its operating cost. To achieve of post-combustion capture requires a CO_2 chemical absorption process. This process results in high energy consumption and is costly. Ways have to be sort to decrease the energy consumption of the process absorption. Pre-combustion can be achieved by converting a fuel to CO and H_2 the CO is then converted to CO_2 by a water-gas shift reaction. This technique can improve both physical and chemical absorption process however; both techniques are very costly and chemically complex. The oxy-fuel combustion technique is not costly and can be achieved with minimum complexity. The process burns fossil fuel with a mixture of pure O_2 (99.5 vol%) that is generated from ASU, and the RFG. The main constituent of the flue gas is CO_2 and H_2O. The concentration of CO_2 will be increased after condensation. The energy consumption in the ASU is high representing 10% of net energy of the power plant. The development for ASU and CPU are studied due to reduce the energy consumption of power plant.

The comparison the technology of integrated gasification combined cycle (IGCC), Natural gas combined cycle (NGCC), and pulverized coal power plant (PC) with the previous CO2 capture technologies. The results showed that the efficiency of PC with post-combustion is lower than the IGCC power plant with pre-combustion capture. The highest efficiency is the NGCC with post-combustion and PC power plant with oxy-fuel combustion. For the operating cost, the PC power plant with oxy-fuel combustion is lowest but NGCC with post-combustion and IGCC with pre-combustion is increased gradually. The PC plant with oxy-fuel combustion and PC power plant post combustion has the same level cost of cost per tonne of CO2 removal. The NGCC with pre-combustion capture has the higher costs. Based on these result, the oxy-fuel combustion is the most competitive technique in comparison to other technique (Hussein A., 2013).

2.2 Oxy-fuel combustion

The oxy-fuel combustion process combines the oxygen with purity more than 95%vol and recycled flue gas as the oxidant that used for combustion the fuel. The flue gas after combusting consists mainly of CO2 and water vapor which can be stored after purifying and compression (Chen L., 2012). The reason that use of almost pure oxygen in the oxy-fuel combustion is the largest portion of the remaining flue gas constituents which consist of nitrogen from air. The oxygen has to be extracted from the air before combustion in the furnace to produce the flue gas that consists of mainly CO2 and water vapor. The oxy-fuel combustion is complex since the characteristics of CO2 is different to nitrogen. The thermodynamic properties show that its density (1.7×higher) and molar heat capacity (1.6×higher) as shown in figure 2. CO2 is much more chemically active than the inert nitrogen. To optimize the combustion process, the ratio between oxygen to recycled flue gases has to be regulated respect to the gas density on mass flows and burner aerodynamics.

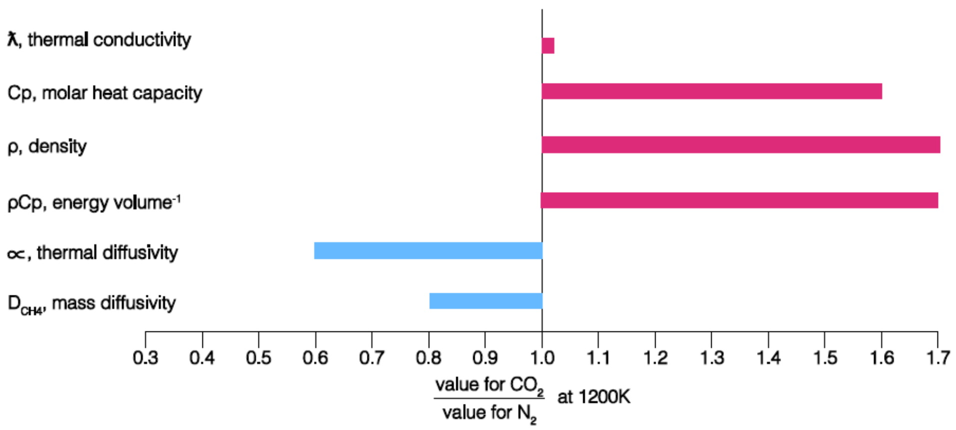

Figure 2- 1 Ratios of combustion relevant properties of CO2 and N2

Due to the difference of the oxidant and the operation of the boiler compared to the air-firing combustion, oxy-fuel combustion is affected by the combustion process recycled flue gas ratio, heat transfer, characteristics of combustion, flame stability and emission formation and reduction. (Suda T., 2007) studied the furnace heat transfer of oxy-fuel coal combustion system which depends on the adiabatic flame temperature (AFT). The oxy-fuel combustion effect on high adiabatic flame temperature is due to the reduced N_2 in the system. But the AFT of air-firing combustion is higher than the oxy-fuel coal combustion at 21% O_2 with CO_2 because of the heat capacity of CO_2. The adiabatic flame temperature in oxy-fuel combustion is similar to air combustion by manipulation of the RFG ratio and the concentration of O_2 at the burner inlet. A retrofit has to select the concentration of oxygen at the burner inlet by regulation of the RFG ratio. The AFT comparison of air and oxy-retrofit combustion with the air combustion has approximately an excess air of 20% and the content of oxygen in the flue gas at 3.3% (v/v). The %excess oxygen which maintain in the flue gas of air-firing combustion and both oxy-dry and oxy-wet combustion is between 3% and 5%. Figure 5 shows the AFT as the air-firing combustion, the fraction of oxygen is around 28% and 5% for wet and dry RFG respectively.

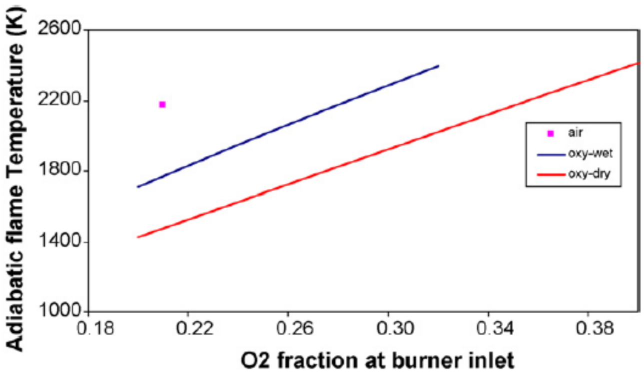

Figure 2- 2 the O_2 partial pressure (fraction) required at burner inlet for oxy-wet and oxy-dry

The radiation and convective heat transfers which can affect oxy-fuel combustion and carbon in ash during air under simulated dry recycle flue gas conditions. It was found that the radiated heat flux increases as the recycle flue gas decreases. The convective heat flux increases with the recycle flue gas increase. The results showed that the radiated heat flux decrease as the RFG ratio is increased due to the combustion process being delayed and lower oxygen. The radiated heat flux profile coal at 3% O2 relates to air firing in the range of RFG ratio between 72% and 75%. The boilers with retrofit oxy-fuel firing system or “Oxy-fuel new builds” boiler is highlighted the importance of preserving an effective balance between radiated and convective heat transfer. Figure 2- 2 shows the trend of heat flux measurement and convective heat flux and adiabatic flame temperature calculation versus RFG ratio. The data of air firing is normalized to use as a baseline. The data showed the acceptable operational range which radiated and convective heat transfer matched on oxy-fuel combustion. The normalized adiabatic flame temperature showed that the air equaled the RFG ratio at 68% and radiated heat flux equal RFG ratio at 74%. It is recognized that the adiabatic flame temperature decreases with the increase of RFG ratio due to the higher mass flow. The expected result as the adiabatic flame temperature and radiated heat flux concur at the similar RFG ratio. The "working range" of RFG ratio associated with the radiated and convective heat fluxes is comparable with air and dependent on coal type (Smart J., 2010).

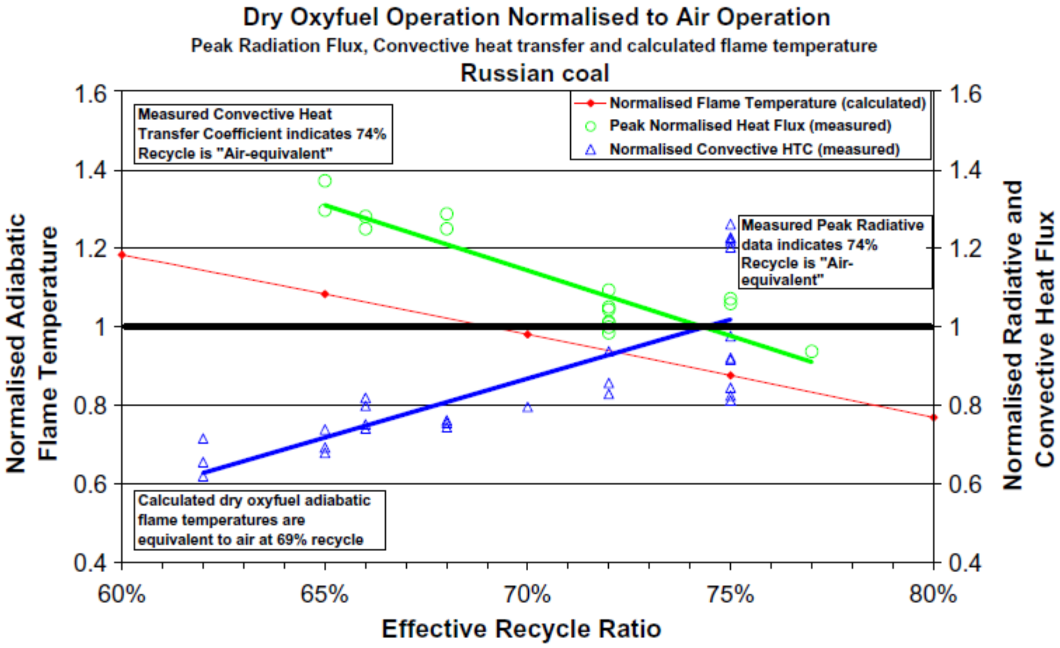

Figure 2- 3 The effect of recycle ratio on adiabatic flame temperature, radiative heat flux, and the convective heat transfer coefficient

The characteristics of flue gas in oxy-coal combustion and the effects of impurities in recycle flue gas (RFG) rate and ratio. The RFG ratio decreases with the increasing of moisture. The moisture is diluted by the concentration of oxygen on the flue gas. Therefore, the coal with higher moisture requires a lower recycle flue gas compared to coal with lower moisture. The RFG ratio is decreased when using coals with high oxygen level. Coals with lower oxygen require a higher RFG rate. The RFG ratio in the bituminous coal (6.04 wt% O2 of fuel) is higher than the sub-bituminous (16.70 wt% O2 of fuel) which relates to 1.6 percentage points at the equal moisture. The RFG rate is reduced around 60% by increasing the O2 concentration of oxidant from 20 mol% to 35 mol%. The oxygen concentration from air separator unit has no clear effects on the RFG rate. is the moisture content of the coal has an effect on the RFG rate, a higher moisture concentration is conductive to the lower amount of RFG therefore the RFG rate is reduced due to the higher coal combustion (Chui EH., 2003). The result of studying dry recycle data of air operation radiated heat flux is between 72% and 75% RFG ratio due to the different radiate properties of carbon dioxide compared to nitrogen. The radiative heat flux peak shifts downstream as recycle rate increases. The convective heat transfer equal to air at 74% RFG ratio which main factors are temperature and mass flow. There is a RFG ratio for both radiated and convective transfer can be reasonable matched between air and oxy-fuel operation which is possible to design the boiler for efficient in both oxy-fuel and air conditions.

2.3 Oxy-CFB combustion

The previous studied about the Oxy-CFB, The Flexi-burn CFB is to demonstrate and develop a CFB boiler power plant with the air-firing of wide range of fuel both fossil fuel, biomass and oxy-fuel combustion with the technologies that reduce carbon-dioxide. In the oxy-fuel combustion, the fuel is burned with a mixture of almost pure O2 and RFG. The lack of N2 produces a flue gas that consists of CO_2 and water vapor. The flexible fuel of CFB can be recompensing the cost of carbon capture and storage by using low-grade fuels. Development of the Flexi-burn CFB based on the basic knowledge and test on the pilot plant and large-scale. The VTT's laboratory scale pilot plant, capacity is 0.1MW. The Canmet's scale capacity is 1MW. The Lagisza scale capacity is 460MWe which design to development and validate the concept of oxy-fuel combustion that operate in both air and oxy-fuel combustion. Moreover, the achievement of CIUDEN CFB pilot plant 30MWth can operate in both air and oxy-fuel combustion. The performance of boiler between air-firng and oxy-fuel combustion system is not dramatic change. The process of Flexi-burn consists of CFB with oxy-fuel system. The output of this project is a design power plant with ait/oxy apply with CFB concept, for demonstrate the large scale of power plant with carbon capture and storage. The different type of coal is tested with this process of 30MWth pilot CFB and test validation at Lagisza 460 MWe which is the first and largest supercritical CFB. Moreover, this project is certify the efficient, reliable and safety of the commercial scale. The innovation of the flexi-burn technology decreases the coal using due to improve the power plant economically particular with CCS operation, lower NO_x and temperature in the furnace is more uniform and, demonstrates the operation which uses both air-firing and oxy-fuel with CCS.

Moreover, the CO_2 emission is reduced due to decreases fuel consumption and presents an attractive alternation to the old power plant that will be expired and consider the using of new technology with higher efficiency and good emission performance.

CHAPTER III
Theory

3.1 Carbon Capture Technologies

The leading systems for the power plant technologies are Integrated Gasification Combined Cycle (IGCC), Natural Gas Combined Cycle (NGCC), Pulverized Coal (PC) combustion steam cycles and Circulating Fluidized bed (CFB) combustion steam cycles. The emissions of CO2 and others gases such as sulphur oxides (SO_X) and nitrogen oxides (NO_x) are produced from the fossil fuel combustion. Various technologies that capture carbon dioxide are developed to reduce the emissions and aim to minimizing global warming. There are three main solutions focused on CO_2 capture which are pre-combustion, post-combustion and oxy-fuel combustion.

3.1.1 Pre-combustion

The pre-combustion capture excludes CO_2 from fuel before the combustion process. These techniques attempt to capture CO_2 between gasification system and combined cycle power plant. Oxygen is used in the gasification of coal or fuel gas, the carbon monoxide (CO) and hydrogen (H_2) are separated from the fuel. The CO is then converted to CO_2 by steam with the following reaction ($CO + H_2O \rightarrow H_2 + CO_2$) and CO_2 is separated by solvent. The CO_2 is then sent to a compression unit for sequestration process and H_2 is sent to combined cycle power plant for generating power as shown in

. While this technique is considered for the combined cycle power plant there are some complex issues compared to other techniques of CO_2 capture.

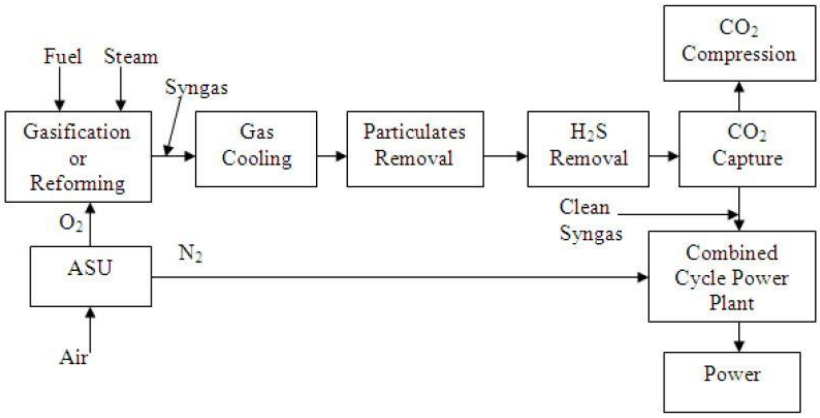

Figure 3- 1 Pre-combustion system

3.1.2 Post-combustion

The post-combustion capture requires a reduction in the particle of fuel, SO_x, and NO_x in the flue gas see **Error! Reference source not found.**. A separation unit is required for this technique following the combustion in the CFB or PC such as chemical absorption, calcium looping, and gas separation membranes. The chemical absorption of process using monoehanolamine (MEA) is used to scrub CO_2 from the flue gas combustion by using absorption tower at high temperature for CO_2 separation from the solvent. Due to the high temperature and low concentration of carbon dioxide in the flue gas, this technique is difficult to achieve in large conventional power plant. Chemical absorption requires a lot of energy for the large separation components as well as a higher operating cost when applied to large-scale power plant. Post-combustion using gas separation membranes for capture CO_2 is currently being developed to deal with the impurity in the flue gases effect on the degradation of absorbent (Hussein A., 2013)

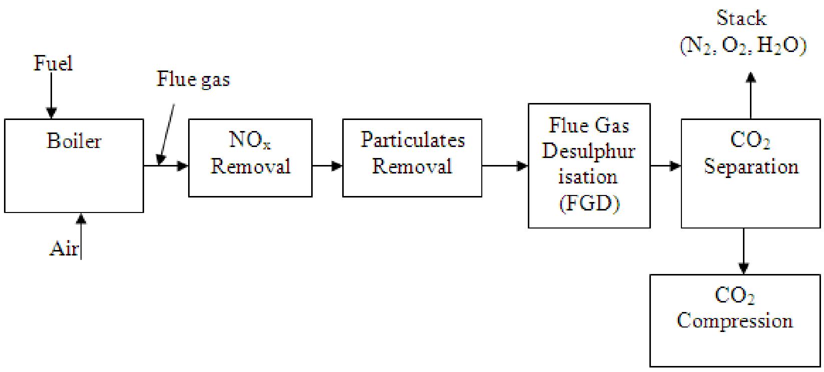

Figure 3- 2 Post-combustion system

3.3 Oxy-fuel combustion

The oxy-fuel combustion is used to capture carbon dioxide from the flue gas combustion. This process is similar to the post-combustion process but this technique uses less chemical compared to post-combustion which has low concentration of CO_2 and the need for a special process to treat for the separation. The fundamental use of oxy-fuel is to increase the concentration of CO_2 in the flue gas because it is easy to compress and separate and as a result, it is cheaper than post-combustion process. The oxy-fuel process utilizes almost pure oxygen mixed with recycled flue gas instead of air in the combustion process. The concentration of CO_2 in the flue gas is high which lowers the operating cost compared to that of the post-combustion process. The process diagram of oxy-fuel is shown in **Error! Reference source not found.**. Sulphur dioxide removal in the PC is achieved by a flue gas desulfurization plant whereas in a CFB, lime-stone is injected to react with the sulphur dioxide and hence its removal. The fly ash is removed by bag house filter and the bottom ash is accumulated at the bottom of the furnace is removed by and extraction system. After the sulphur dioxide and particulate matter is removed, the concentration of flue gas which consists mainly of CO_2 and water is around 95%. The parameter of the purity of oxygen feed from air separator unit, and the excess of the oxygen/fuel has an effect on the purity of CO_2

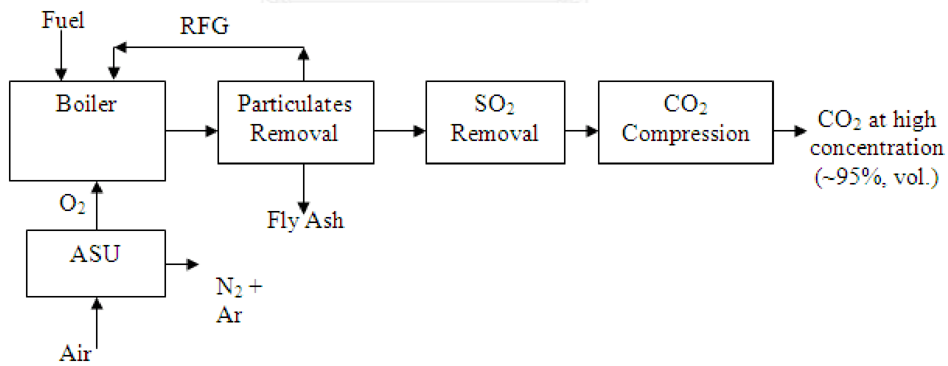

Figure 3- 3 Oxy-fuel combustion system

The recycled flue gas is mixed with the almost pure oxygen to control the temperature in the furnace and in doing so can protect the material in the furnace. The size of furnace can be reduced since the recycled flue gas is introduced. The oxy-fuel combustion can be retrofitted into existing conventional power plant because it can operate at the same flow field condition.

Air separation units are used for production oxygen and produces two steams consisting of a stream of nitrogen with, other products is vented to the atmosphere and the oxygen stream which is introduced in to the furnace. The air separator unit uses a lot of energy and this can affect the cost of operating with a high CO_2 capture. The oxy-fuel combustion can compete with other CO_2 capture technologies. The use of recycled flue gas and pure oxygen instead of air to burn in the coal-fired power plant can lead to changes in the flame temperature and radiation heat transfer in the furnace accompanied by higher emissions in the flue gas. The reasons for these changes are that the specific heat capacity of CO_2 is higher than N_2 in the air-fired power plant and the properties of gas mixture radiation. Low molecular diffusivity of oxygen in CO_2 compared to N_2 and and other changes on the characteristics of the gas mixture such as viscosity, thermal diffusivity, (Hussein A., 2013).

3.3.1 Oxy-coal combustion at atmospheric with flue gas recycle

The oxy-coal combustion systems retrofit with the existing coal-fired power plant to include the option of carbon dioxide capture. The flue gas recycled ratio is varied to control the temperature in the furnace and the flue gas consists of the primary steam that is removed through condensation and carbon dioxide that is purified before sent to the compression unit and the separation unit. The equipment for the oxy-coal fired as described below:

3.3.1.1 Air Separation Unit *(*ASU*)*

The oxy-fuel retrofits with the existing coal-fired power plant and the addition of air separation unit ASU where this equipment is used in conjunction with the injection of pure oxygen into the furnace for combustion. The ASU can accommodate the volume and impurity demand of a large scale of coal-fired power plant. The process compresses, cools, and cleans the air before send to the distillation column to separate air into the almost pure oxygen and the nitrogen-rich stream. The air separation consumes around 0.24 kWh/kg of energy with O_2 at 95% Oxygen purity. Even though the oxy-fuel combustion from coal requires an oxygen purity of about 85% to 98% that is less than the need in the industrial process of about 99.5% to 99.6%. The separation processes can consume a gross power output of more than 15%(2)

3.3.1.2 Carbon dioxide purification unit *(*CPU*)*

The carbon dioxide purification unit consists of a gas clean up unit that is used for removing water and particle of other impurity from the flue gas before sending the gas to a compressor for sequestration. Since oxy-combustion can be retrofitted with existing CFB combustion, the concentration of NO_x and SO_x can be reduced in the flue gas by a process of ammonia anhydrous and lime-stone injection respectively. On the other hand, if oxy-combustion is retrofitted with the PC combustion power plant the unit the removal SO_x, NO_x and particle matter can be achieved by the use of selective catalytic reduction (SCR), electrostatic precipitator (ESP) and flue gas desulphurization unit. There is a question of safety associated with the transportation and storage of the non-condensable impurities such as O_2 that can contribute to the cavitation damage and corrosion of the pipeline after the handling of acid gases (SO_x, NO_x, non-condensable N_2, O_2 and Ar which are removed in the process and are vented by using a non-condensable gas purification unit. A gas purification unit consists of multistage compressor with a separating inert gas inter-stage cooling. However, it should be weighed against the result of the puritying in the storage with a compromise between efficiency losses and operational costs of the purify process and the safety demands of transportation and storage (Kanniche M.,2010).

3.3.1.3 Recycled flue gas *(*RFG*)*

The recycled flue gas is used instead of nitrogen and adjusts the firing temperature in the furnace. Darde A., (2009) focused on the Oxy-PC whit recycled flue gas being recycled in the different positions of primary air which is used for coal transportation. A secondary stream is used to the benefit of energy efficiency. The primary recycle stream is reheated to 250 to 300 °C to extract moisture from coal feed and the secondary stream is recycled at higher temperature excluding drying to eliminate thermodynamic losses caused by cooling and re-heating.

3.3.2 Oxy-coal combustion pressurized system

The pressurized oxy-coal combustion system is aimed to improve the energy efficiency by recovery the latent heat of steam in the flue gas. The higher pressure is to reduce the volume of flue gas which can effect auxiliary equipment and a reduction in the investment cost for the same power output. L Chen et al (2012) concluded the higher operating pressure improves the efficiency of the process because recovery latent heat from the flue gas that increase temperature and reduce the auxiliary power consumption. The heat transfer characteristics at higher operating pressure and the furnace with its heat exchangers have to be redesigned to accommodate these changes in the process characteristics.

3.3.3 Performance of the oxy-coal combustion systems

L Chen et al (2012) is concluded the efficiency of plant generation and the capital cost of CO_2 capture technologies from , the result as the **Error! Reference source not found.**4 show post combustion had a loss of efficiency of about 10 percentage points compared to conventional PC power plant. The atmospheric oxy-fuel combustion shows increasing 1 to 5 percentage point compared to post-combustion capture. The pressurized process delivers an increase of 3 percentage point's efficiency. The higher saturation temperature of water at the high pressure is the key advantage of pressurized oxy-fuel system in that it can recover more thermal energy and latent heat that were previously assumed. Though the consumption of the ASU in the pressurized oxy-fuel is higher than others it can reduce consumption in the CO_2 compression and the recycled flue gas compressor resulting in a higher overall efficiency.

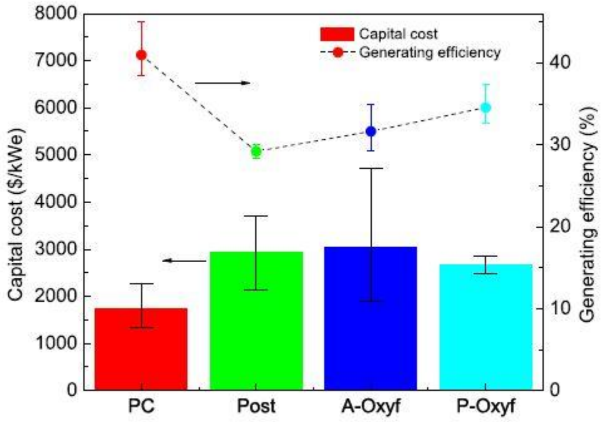

Figure 3- 4 The comparison of the generating efficiency power plant and capital-cost of CO_2 capture technologies. PC: Conventional PC system, Post: PC with post capture, A-Oxyf:Atmoshperic oxy-coal with flue gas recycle, P'Oxyf: Pressurized oxy-coal with flue gas recycle

3.4 Effect of parameter on oxy-fuel combustion characteristics

By using pure oxygen mixed with recycled flue gas instead of air in the oxy-coal fired power plant the characteristic of the modified power plant indicates that under normal operating conditions the oxy-fuel power plant can operate at high combustion efficiency and is compares favorably in term of thermal performance and low emissions. These parameters are based upon the design and operating conditions of the existing power plant resulting from the changes in oxygen concentration, size of particulate matter and recycled flue gas.

3.4.1 Oxygen Concentration

The concentration of oxygen has an effect on the flame stability and heat transfer characteristics in the oxy-fuel combustion owing to the conventional firing system and the concentration of oxygen. The difference in the properties of carbon dioxide and nitrogen can delay the ignition time of volatile matter released and hinder oxidizing of the coal particles. The higher oxygen concentrations have safety implications whilst providing higher operating efficiency. The oxy-fuel combustion that has RFG with 28 vol. % O_2 is safer than with 21%O_2in the secondary stream of the pilot-plant (Toftegaard MB., 2010) The oxy-fuel combustion with differing amounts and concentration of RFG with O_2 to the carrier gas and feed oxidized gas stream. The range of oxygen concentration is between 25% to 36% by volume which has been found to support good flame behavior and characteristics of heat transfer compared to air-fired. The improvement of oxy-fuel is successful when compared to air-fired power plant with the decreased concentration of CO and flame stability is attained and lower content of carbon in the ash.

3.4.2 Recycle flue gas

The recirculating flue gas is recycled into the furnace to maintain the combustion temperature and heat transfer characteristics in the furnace of the air-fired combustion power plant.

3.4.3 Particle size

The particle size has an effect on the flame propagation speed, devolatilized process, and ignition temperature .Suda T., (2007)research on the different particle diameters)50 and 100 micrometer (to investigate the effect of coal particle size by result as shown on the propagation behavior of flames, the flame propagation velocity decreased in no significant change .However, the reason for that it is decreased heat transfer conduction process between coal particles and gas .The flame stability in the O2/CO2 mixed should be using smaller PC particles.

3.5 Conventional CFB Circulating Fluidized Bed Boiler

The description process of Circulating Fluidized Bed Boiler is taken from an operation manual of Foster Wheeler.

3.5.1 Principle of fluidized bed boiler

Fluidizing is achieved by blowing air through the bed material lying on the grid (air distributor). Fluidizing beds can be divided into four categories. The type of fluidizing bed is dependent on the air velocity in the bed. As the velocity is increased the bed changes from fixed, through bubbling and turbulent, to circulating. Bubbling beds operate at superficial velocities of less than about 2 to 3 m/s; there is also a distinct visible bed level. Above this minimum velocity the bed expands more and particles become entrained in the flue gas and are carried out of the bed. There is no longer a distinct visible bed level, but the bed become less and less dense through to the furnace. The coarser entrained particles are separated in a hot separator and returned back to the bed.

This is the circulating fluidized bed (CFB) principle on which CFB boilers operate. Typical superficial velocities are 4.5 to 5 m/s. typically combustion takes place at about 850 to 900 °C bed temperature. For fuels containing little ash, sand is used to form the bed material. If the fuel contains sulphur, limestone is often added to capture the sulphur and in this case the limestone together with the fuel ash may form the bed material.

3.5.2 Advantages of the CFB boiler

CFB boiler can burn a wide range of low grade fuels, due to the large heat capacity and mixing of the bed.

- High combustion efficiency, due to turbulent mixing and long residence time in the circulating bed
- Low SO_2 emissions, due to ease of sulphur retention with limestone at ideal temperatures
- Low NOx emissions, due to low bed temperature and staged combustion
- Low CO and CxHy emissions, due to turbulent condition and long residence time and mixing in the separator
- Stable operating conditions and boiler response due to the high heat transfer from the circulating material
- Good turn down rates due to heat transfer being approximately proportional to load. No need to slump section of the bed at low loads
- No need for in-bed tubes which are subject to erosion

- Fewer fuel feed points due to better mixing in the bed compared to bubbling beds.

3.5.3 CFB compact Technology

Solid Separator is a vital part of the CFB technology. The solids separator is primarily designed to provide an efficient separation of the entrained solids from the hot flue gas and return most of the unburned carbon and available calcined limestone for more efficient use. Inert ash particles are also returned, these particles are needed to maintain the proper bed inventory and quality. Gas and solids flow into the separator from the furnace through an inlet channel, and gas flows out from the separator through cylindrical vortex finders. The separated solids fall to the bottom of the device and are returned to the furnace. The gas flow in the separator is a swirling vortex type. Due to the centrifugal effect, solid particles are swept to the separator walls and continue to flow along the wall surface. This phenomenon promotes particle stream separation and helps the particles to fall to the bottom of the separator for return to the furnace.

In the return channel, the normal wall seal system is replaced by another patented innovation, the so called wall seal which allows solids to return to the furnace and effectively prevents the gas flow upstream. The wall seal openings are fabricated in the straight cooled furnace wall panels which are protected against erosion with a thin layer of refractory around the openings.

3.5.4 The Benefits of the CFB Compact

The main benefits of the CFB Compact design are derived from the cooled panel wall structure used for the whole CFB system. The separator and return channel system are integrated with the furnace and connected into the same water-steam circuit. This construction saves space and operates at the same temperature thus avoiding differential thermal expansion. Consequently, no bellows are required between the furnace and the Compact separator and return channel. Cooled walls eliminate the need for multilayer, insulating refractories which are exposed to high temperature gradients and thus may require maintenance. Thin, single layer refractories are used in the CFB Compact only in the locations that may be susceptible to wear of the metal surface. These thin refractories are cooled by the panel walls and the design has been proven in long term operation. This enables fast changes in process conditions and eliminates any limitations of start-up times due to thick refractories. The high quality manufacturing of panel walls is routine work that is carried out at most boiler works. This manufacturing is usually done using automatic welding machines. With the CFB Compact design most manufacturing can be completed in the shop thus reducing the construction time and risks of unexpected delays.

3.5.5 Combustion of Fuels

Combustion is defined as the rapid chemical combination of oxygen with combustible elements of a fuel resulting in the release of heat energy and light.

3.5.5.1 Type of Combustion

Oxidation is the simplest form of combustion. Oxygen combines with elements, such as iron, to form an oxide (i.e. rust). Silver tarnishes; copper takes on a greenish coating. This process is a very slow form of combustion. Oxidation takes place on many parts of the boiler, such as tube metal surfaces, air and gas ducts, air heaters and ID fans.

Spontaneous combustion is a process where, under some conditions, combustion maybe self-starting. Fires resulting from spontaneous combustion occur occasionally in coal yard piles, storage bins (silos) and bunkers. Coal piled outdoors combines slowly with oxygen in the air and moisture, producing a chemical reaction and giving off heat. If the heat does not dissipate fast enough, temperatures rise and the reaction speeds up until it eventually becomes a burning fire.

Normally, the combustion process begins when applying heat (ignition energy) to a fuel in the presence of oxygen. Flammability of a fuel depends on how easy it turns into a gas unless it is in a gaseous form already. With the exception of solid carbon, most fuels burn from a gaseous state. Part of the fuel introduced to a furnace as a liquid or solid will vaporize due to the heat in the furnace. This vapor will ignite readily and rapidly, and supply heat for the combustion of the solid carbon. The combustion of carbon will take place at a slower rate and, therefore, requires more time in the presence of heat and oxygen have complete combustion.

3.5.5.2 Requirement for Combustion

There are three factors or conditions necessary to produce combustion. These conditions are 1) the presence of a fuel (a combustible material), 2) enough oxygen to support combustion and 3) enough heat to bring the fuel to its ignition temperature and keep it there. These three requirements are all necessary for combustion to occur

3.5.5.3 Principal Combustion Constituents of a Fuel

Fossil power plant fuels (coal, oil and gas) have the same basic combustible components: carbon, hydrogen and sulfur. In combustion, the carbon and hydrogen are the major elements. They burn and form CO2 (Carbon Dioxide) and water vapor. Sulfur forms corrosive compounds that are released in the combustion process. SO2, sulfur dioxide, forms an acid when mixed with water. Other elements contained in fuels may be considered as impurities which can affect ash accumulations throughout the boiler. Air is the usual source of oxygen for combustion. Air is a diluted source of oxygen and this is of considerable significance in furnace design and operation. Oxygen makes up about 21 percent of air by volume. Oxygen is the only active element in air necessary for combustion. A large amount of nitrogen in air (about 80 percent) performs no useful duty in the burning process. Nitrogen, when exposed to high temperature, forms NO_x (nitrogen oxide), known air pollutant . Air also contains a small amount of water vapor. Heat must be present to cause ignition. Ignition is raising a substance to the minimum temperature at which combustion becomes selfsustaining. The temperature at which this begins is known as ignition temperature. Until this point is reached, an external source of ignition energy is needed.

Natural gas or fuel oil is generally the medium for ignition energy on Foster Wheeler CFB boilers. High energy igniters (like spark plugs) electrically ignite small quantities of gas or fuel oil for initial flame (heat). This ignition then supplies ignition energy to ignite the main flow of natural gas or fuel oil that increases bed temperatures to the point where solid fuel can be introduced and ignited.

3.5.5.4 The Combustion Cycle

Enough air must be present for combustion to take place in the furnace. Primary and secondary air fans supply combustion air to the furnace. Primary and secondary air is heated in the tubular air heater before entering the furnace. On balanced draft boilers, the resulting combustion gas and any excess air is removed from the furnace by the induced draft (ID) fan. Air entering and flue gas leaving the furnace are measured in kg/s. Fuel entering a furnace requires a definite quantity of air to complete combustion. This is the "theoretical air" required for complete combustion under perfect conditions, also called 100 percent total air. However, more air than the theoretical amount must be used to assure complete combustion in the imperfect conditions of the steam generator. Excess Air is the term used to describe what is more than theoretical air. Excess air would not be necessary if it were possible to have a perfect mixture of fuel/air for combustion.

Excess air is not involved with the burning process. It merely assures that complete combustion takes place before leaving the furnace. Oxygen analyzers measure excess air at the economizer inlet.

3.5.5.5 Fuel and Mixing

Effective mixing of fuel and air is necessary for complete combustion. Combustion is a chemical process. When mixing oxygen in the air with the carbon, hydrogen and sulfur in the fuel in definite proportions at the ignition temperature, they will combine to form fire.

3.6 Excess oxygen trim control and oxygen analyzers

Increased operating and maintenance costs have forced boiler operators to make the most of expensive fuel by optimizing efficiency of steam generator equipment. Probably the most cost effective means of improving boiler efficiency is by controlling excess air levels as measured in the flue gas to a minimum.

Excess air is necessary in the combustion process. Excess air can confirm complete combustion; it also is required for SO2 capture. It results in a known, but accepted, heat loss. Excess air is also essential from a safety standpoint, without it, the amount of oxygen in the furnace could drop below a theoretical (stoichiometric) air level during transient conditions, possibly leading to a fuel rich mixture and possible boiler explosion.

Discharge from secondary air fan is distributed around the furnace to supply some combustion air at air nozzles located in all four walls of the furnace, just above the primary air nozzles. Upper secondary air is primarily used for additional combustion air that helps in "staged" combustion. Staged combustion is where fuel is ignited at different levels in the furnace. Secondary air is also used for bed temperature control and excess oxygen trim. Actual secondary air flow to the furnace is measured by flow elements and transmitters. These values are square rooted, temperature compensated and summed to provide an equivalent mass flow to the furnace.

Air flow measurement is adjusted by a multiplier to compensate for O_2 trim. Amounts of oxygen in flue gas is sampled and measured by oxygen analyzers located in the back pass between Super heater 1 and Economizer sections of tube bundles. Each analyzer (if several) sends an independent signal to the control room where it is checked by the control room operator. Experienced operators use this information to optimize boiler operations. These signals are signs of complete combustion and excess air. Safe and cost effective operation should be the goal of everyone concerned.

Oxygen analyzers need to be recalibrated with test gas regularly. Recalibration should be done at least every three weeks or whenever the O_2 split differential between various analyzers) becomes greater than 0.5 percent (.5 percent) and fuel distribution is determined not to be the root cause of excessive O_2 split. Where applicable, after the analyzers have been recalibrated and the O_2 split has not been corrected, wall seal return leg temperatures should be compared to determine if coal feed is balanced. First, try to adjust individual air drop air flows to balance temperatures (air to fuel feed). If this fails, operators may have to adjust slightly the coal proportional distribution valves on the conveyors (if applicable). This requires cooperation between control room and operator in the field adjusting proportional distribution valves. Minor adjustments at this location can quickly change coal flows to the wall seal return leg. Operator should make only few complete turns on this valve handle at one time. Operator must be checking this activity. Check change in the wall seal return leg temperatures and excess O2. Do not make another adjustment for about 10 minutes to allow boiler operation to stabilize. Adjust as necessary.

3.7 Emissions

3.7.1 Sulphur dioxide emissions

The CFB boiler is ideal for meeting current requirements for SO2 emissions. By feeding limestone into the bed a high sulphur retention rate is achieved with rather low calcium/sulphur molar ratios. The chemical reactions may be expressed as:

Calcination of limestone:

$$Heat + CaCO_3 \rightarrow CaO + CO_2 \quad (3\text{-}2)$$

Sulphation:

$$CaO + SO_2 + \frac{1}{2} O_2 \rightarrow CaSO_4 + Heat \quad (3\text{-}3)$$

Sulphur capture is most efficient at a bed temperature of 850 °C.

3.7.2 Nitrogen oxide emissions

Due to the low combustion temperature "thermal" NO_x formation by oxidation of molecular nitrogen in the air is negligible. NO_x formation due to nitrogen in the fuel is reduced by "staged" combustion. That is, in the lower part of the bed, combustion takes place under reducing conditions which leads to the formation of molecular nitrogen N_2, instead of NO_x as in the case with oxidizing conditions. Additional secondary air to complete the combustion is introduced at higher levels. By injecting ammonia into the furnace or separator further lower NO_x emission levels can be achieved. By using 25 % NH_3 solution the feeding system is very simple consisting of a storage tank, feeding lines with necessary valves and nozzles at the injection points.

3.7.3 Combustible Material Emissions

CO emissions are low due to the turbulent mixing in the bed and mixing in the separator. Similarly hydrocarbons C_xH_y and residual un-burnt carbon are minimized due to the turbulent mixing in the bed and longer residence time in the circulating bed type boiler.

3.7.4 Particulate Emissions

Particulate emissions are reduced in the CFB Compact boiler, as in other boilers, by the use of a bag filter after the boiler.

CHAPTER IV
Process and Modeling

This chapter explains description of oxy-fuel combustion of coal-fired power plant simulation in GateCycle application. The oxy-fuel combustion of coal-fired power plant consists of steam turbine generator, steam turbine, feed water heating, condensate system and recycle flue gas system. The process of oxy-fuel combustion of coal-fired power plant is the combustion process which consists of pure oxygen and carbon dioxide (CO2). The pure mixture of O2 and CO2 combust at the higher combustion temperature therefore the oxy-fuel process is more efficient burning. The study aims to analyze the performance of oxy-fuel combustion of coal-fired power plant. Firstly, the coal-fired power plant which is developed is validated with data of design condition. Then, the performance of the process is investigated the effect of operating conditions to find optimal operating conditions. Finally, the heat recovery of recycle flue gas of oxy-fuel combustion is investigated.

4.1 Process flow diagram of oxy-fuel combustion of coal-fired power plant

The process of oxy-fuel combustion of coal-fired power plant is the combustion process which consists of pure oxygen and carbon dioxide (CO2) and burns at the higher combustion temperature then the oxy-fuel process is higher combusting. For the process flow diagram of oxy-fuel combustion of coal-fired power plant that is developed as Figure 4-1 which consists of steam turbine generator, steam turbine, feed water heating, condensate system and recycle flue gas system.

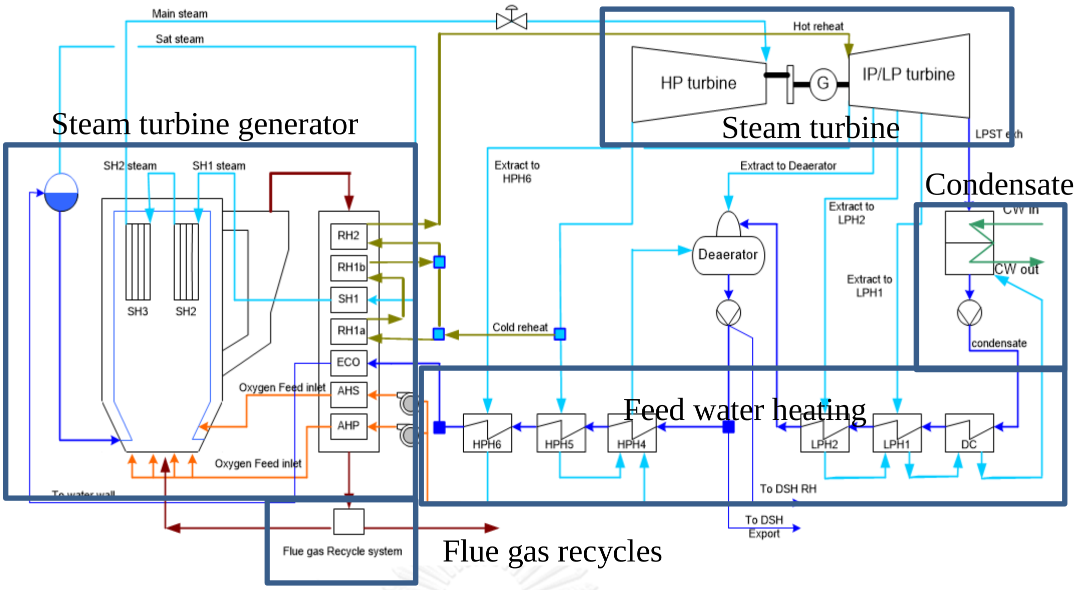

Figure 4-1 The process flow diagram of oxy-fuel combustion

<u>Steam Turbine Generator</u>

The steam turbine generator as shown in Figure 4-1consists of the boiler that include internal heat exchanger superheater2 (SH2), superheater3 (SH3) and external heat exchanger or the back path section which include the reheater2 (RH2), reheater1B (RH1B), superheater1 (SH1), reheater1A (RH1A), economizer(ECO) and the air heater of primary(AHP) and secondary(AHS) feed of oxygen and drum.

Heat for the 115 MW generators is derived from burning coal in an outdoor sub-critical combustion boiler with balanced draft and, natural circulation including a single reheat section. A Foster Wheeler boiler with a Boiler maximum continuous rate (BMCR) of 372.884 t/h of steam which can driver a 126.508 MW Turbine maximum continuous rate (TMCR) turbine generator,. The unit is supported by various auxiliary systems. A boiler is capable of continuous stable operation down to 44.3 MW without gas firing support.

Steam Turbine

The section of steam turbine as shown in Figure 4-1consists of the steam turbine 3 stages that is high pressure turbine (HP), Intermediate pressure turbine (IP) and Low pressure turbine (LP) and the generator of the steam turbine.

The turbine is a tandem compound machine with a single cylinder HP turbine and an IP turbine which is supplied with steam from the boiler reheater. The turbine has two cylinders with a single exhaust. The IP & LP Turbines are housed in a common cylinder. The normal rated steam pressure and temperature at HP Turbine inlet is 166.0 Bara and 565 ^{o}C. The rated steam pressure and temperature at IP turbine inlet is 34.4 Bara and 563 ^{o}C. The turbine drives a generator at a speed of 3000 rpm. The maximum total generator output is 130.298 MW. Bled steam from the turbine can be released at a load of 35% and can be closed when load falls below 30%. The condenser pressure is maintained at 0.071 Bara. Feed water is taken from the deaerator feed water storage tank by two Boiler Feed Water Pumps (BFP) each with a 50% capacity. Feed water from the BFPs can be discharged through three stages of high pressure (HP) regenerative feed water heating. A feed water flow control station controls the flow of water through the economizer into the boiler drum. Separation of steam and water is accomplished in the boiler drum. The steam passes from the top of the boiler drum to superheater sections equipped with a desuperheating section to control the seam temperature. Superheated steam passes from the boiler and is expanded through the turbine. After expanding through the HP Turbine, the steam is returned back to the boiler reheater and passing through its associated attempt operator section of the boiler. Steam leaves the reheater and is expanded through an IP-LP Turbine before being exhausted into a surface condenser. A once-through cooling water system removes latent heat which is rejected at the LP Turbine exhaust steam. The steam from the exhaust of the LP turbine passes into the condenser. The waste heat is lost into the cooling water system as it is returned to the sea.

Feed Water Heating

The feed water heating as shown in Figure 4-1 is consists of two stages of feed water pumping that is the boiler feed water pumps and condensate extraction pumps, three high pressure feed water heaters (HPH3, HPH4 and HPH5) at the boiler feed water pump discharge and two low pressures feed water heaters (LPH1, and LPH2) at the condensate extraction pump discharge and one direct contact heater (deaerator).

Each feed water heater drain is normally cascaded to the next lower pressure heater and the lowest pressure heater drain is cascaded to the condenser. All heater drains are gravity type. Each of the low pressure heater stage can be bypassed individually. The high pressure heater stage is provided with a bypass facility. Steam for regenerative feed water heating utilizes steam extracted from the turbine cycle. Bled steam for the highest pressure feed water heater (HPH6) is taken from an intermediate stage of the IP Turbine. Steam condensing in the HPH 6 cascaded as flashed off steam for heating steam for HPH4. The exhaust from the HP Turbine (Cold Reheat steam) is supplied to HPH5. Bleed steam for deaerator is taken from the IP Turbine. Two intermediate stages of the LP Turbine supply extraction steam to LPH2 and LPH.

Condensate System

The condensate system as shown in Figure 4-1 is the condenser that receive the exhaust steam from the low pressure steam turbine. Condensate is extracted from the condenser hotwell and pumped by two vertical condensate extraction pumps, each of 100% capacity, through the gland steam condenser (GSC), two stages of low pressure regenerative feed water heating and sprayed into a direct contact deaerating heater. The condenser is cooled with sea water from circulating water from cooling water pumps. The sea water is pumped through the condenser and discharge water to a discharge seal pit for further discharge of water back to the sea on the downstream side.

Recycle flue gas system

The recycle flue gas system as shown in Figure 4-1 is the section that separates the flue gas from the outlet boiler into 2 parts consists to flue gases that emit to the atmosphere pressure and recycle flue gas which sends back in to the boiler by using the splitter. The splitter can change the secondary ratio to vary the flue gas ratio that sends back into the boiler. The recycle flue gas is used to maintain the combustion in the boiler due to the high combustion of oxygen and maintain the volume flow in the boiler.

4.2 Modeling

In the study uses the GateCycle Application for the oxy-fuel combustion of coal-fired power plant simulation for investigating the performance of the power plant. The first part, the overview of the GateCycle is explained. The secondary part, the unit model of the oxy-fuel power plant in the GateCycle is illustrated in each part such as steam turbine generator, boiler, feed water heater and the heat exchanger which represent the detail of unit and the performance evaluation. The final part, the model validation is investigated. The process flow sheet of the oxy-fuel combustion of coal-fired power plant is shown in the Figure 4-2.

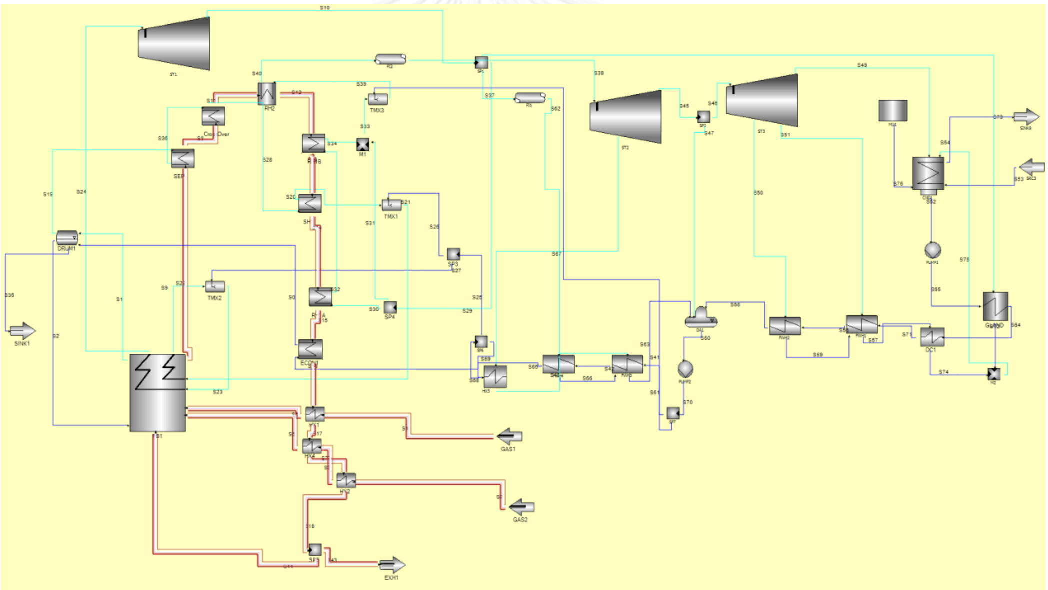

Figure 4- 2 The process flow sheet of oxy-fuel combustion of coal-fired power plant

4.2.1 Overview of the GateCycle Application

The GateCycle application is an application used for design and performance evaluation of thermal power plant systems at both design and off-design points. The GateCycle application was developed by GE Energy. The GateCycle application combines an instinctive, graphical user interface with detailed analytical models for the thermodynamic, heat-transfer and fluid-mechanical processes within power plants, allowing design and simulation studies of any complexity such as analyzing an overall cycle for a proposed power system or cogeneration station. This analysis produces data on operating performance at all points throughout the station, including overall cycle efficiency and power, simulating the performance of existing systems at off-design operating conditions, and predicting the effect of proposed alters or enhancements to the existing plants. The GateCycle application enables to define and analyze the power plant cycles. The design cycles interactively can be select equipment icons from a toolbox and graphically connecting them together. Finally, run the model to determine the performance of the complete power plant.

The model of GateCycle consists of physical layout of a power cycle built in the model flow sheet. Each plant layout (model) has one design (reference) case and any number of additional cases (off-design) associated with its. The design case defines the physical size (and other parameters) of the equipment. The off-design cases are used to analyze how the plant design performs as conditions change.

More detailed descriptions of each step to create a GateCycle simulation model are outlined below.

1. Draw the model diagram, connecting the equipment icons with streams.

The equipment icons from the equipment toolbox is selected, needed for the flow sheet (the model design area of the application, containing the layout of the machine icons and the streams that connect them.) calculations, and position them on the GateCycle main window layout area.

2. Enter required data.

Feed streams (Source and Gas) and exit streams (Sink and Exhaust). The equipment for each feed and exit stream in the model diagram to view properties of equipment in the properties window. The property data in the window is entered. In most cases, default values are supplied for every parameter. The flow rate and thermodynamic property/composition of the inlet streams need to confirm.Equipment icons. Select an equipment icon, in the diagram, to see the properties in the Properties window. The learning more about calculation options, ports and properties for that equipment icon select help from the context menu.

3. Run the simulation model.

When the model has all required information, the model is ready to run simulation. At this point, the run commands are enabled and select on the run tool in the analysis toolbar or select run cycle from the analysis menu to begin the GateCycle calculations.

4. Review your model results.

The log file and reporting features of the GateCycle application are used to analyze the simulation results. If any errors are reported, refer to the list error file and list log file commands on the analysis menu to review the error and calculation logs.

The GateCycle calculations are prepared by enter enough data to specify the design and operating conditions for each equipment icon and overall system calculations.

System Data

System data is entered by way of the Properties Editor. The System Properties include special values to control the calculations, such as iteration limits and tolerances , as well as parameters to specify overall cycle values , such as generator efficiencies, ambient conditions and BOP (Balance of Plant) power losses. In this study the system properties include

System Input – Properties

The GateCycle application calculates the thermodynamic properties of air, steam, and gas mixtures using property routines which use numerical. For gas flows, the calculations are performed for each individual constituent in a gas mixture (N_2, O_2, H_2O, etc.) and then mixing laws are applied to determine the properties of the gas mixture

Steam Property Method

There are four available options that the input selects the property method used to calculate steam and water properties.

Method 1 is a tabular look-up procedure based on Keenan & Keyes – the maximum P is 2208 psia, maximum T is 2500F;

Method 2 is the 1993 ASME steam property formulations - the maximum P is 14000 psia, maximum T is 1600 F. This method is equivalent to the 1967 ASME steam property formulations with updated FORTRAN code and a few bug fixes;

Method 3 is based on a publication from Stanford (Thermodynamic Properties in SI Units System International Units, or TPSI) – the maximum P is 14000 psia, maximum T is 2500F;

Method 4 is the newest standardized property method for steam and water: IAPWS-IF97. This method is also known as the 1999 ASME steam tables. – the maximum P is 1000 bar with a maximum T of 2000C in the 1 to 100 bar pressure range and 800C in the 100 to 1000 bar range.

Gas Property Method

This input selects the method used for calculating the gas properties of the eleven gas constituents in GateCycle analysis (H_2 O_2 CH_x CO CO2 N_2 SO_2 AR H_2S COS H_2O). There is one only option that proposed by ASME PTC4.4.

Gas Property Set Limits

The temperature and pressure limits of the ideal gas property methods when did not use the streams that contain water as shown in the table 4.1:

Table 4- 1the temperature and pressure limits of the ideal gas

Method	T_{min}	T_{max}	P_{min}	P_{max}
1	200K (-100F, -73C)	No limit	0 psia/kPa	No limit

Real Gas Correction Method: These real gas properties are pressure corrections to the enthalpy and specific heat as calculated by the ideal gas properties. The options are:

0 = Ideal Gas – No Real Gas Corrections

1 = Lee - Kesler

2 = Peng - Robinson

3 = Soave - Redlich - Kwong

4 = Benedict - Webb - Rubin (- Han - Starling)

5 = Redlich - Kwong

Method of Gas Property Reference Conditions

Enthalpies in the GateCycle application are a comparative number. All calculations dealing with enthalpy are in terms of enthalpy differences then the absolute value enthalpy does not change results. In the GateCycle application, the zero-point of enthalpy is at the triple-point for water (32F), which is the standard. For gases, the zero point is at 60 °F (15.56 °C) by default.

Table 4- 2 The method of gas property reference conditions

Method	Description
Use Default Reference Conditions	With this option, the triple point of water is used for water and steam properties, and 60 °F is used as the reference temperature for the enthalpy of gas streams.
Input Reference Conditions	To specify Reference Temperature and Reference Pressure for the reference point of gas property enthalpy. The default values for these two inputs are set to the temperature and pressure for the triple point of water to accommodate for the alignment of gas and steam property sets.

Fuel Flows

The specification of fuel used in GateCycle combustor, gas turbine, gas source and duct burner models by entering the lower heating value (LHVFuel Lower Heating Valve) of the fuel and the mass or volume percentages of the major composition. Stoichiometric calculations are used to determine the composition of combustor exit flows from the supplied fuel and air makeup (complete combustion is assumed). The input LHV is then used to determine the energy content of the fuel and therefore the temperature of the combustion products. This means that the GateCycle application does not calculate heating value from the fuel compositions.

System Gas

System gas of the system properties provides the following ability.

Automatic calculation (based on the input composition) of the Lower Heating Value by the GateCycle application, instead of requiring this input from the user.

The heating value of fuel can be specified both higher heating value (HHV) basis and lower heating value (LHV) basis.

The composition of fuel can be specified in terms of mass fractions or mole fractions.

Heating Value Method

Input LHV

Input HHV

GateCycle's LHV

ASTM D3588-98 LHV

Table 4- 3 The allowed fuel compositions in the system fuel data

Hydrogen (H_2)	Ethane (C_2H_6)
Oxygen (O_2)	Propane (C_3H_8)
Methane (CH_4)	n-Butane (C_4H_{10})
Carbon Monoxide (CO)	iso-Butane (C_4H_{10})
Carbon Dioxide (CO_2)	n-Pentane (C_5H_{12})
Nitrogen (N_2)	iso-Pentane (C_5H_{12})
Sulfur Dioxide (SO_2)	neo-Pentane (C_5H_{12})
Argon (Ar)	n-Hexane (C_6H_{14}, gas)
Hydrogen Sulfide (H_2S)	n-Heptane (C_7H_{16}, gas)
Carbonyl Sulfide (COS)	n-Octane (C_8H_{18}, gas)
Steam (H_2O)	Naphtalene ($C_{10}H_8$)
Ammonia (NH_3)	DecaHydroNaphtalene ($C_{10}H_{18}$)
Methanol (CH_3OH)	Distillate ($C_{12}H_{26}$)
Ethanol (C_2H_5OH)	Ethylene (C_2H_4)
Propanol (C_3H_7OH)	Acetylene (C_2H_2)
Hydrogen Cyanide (HCN)	Nitric Oxide (NO)
Methyl Mercaptane (CH_4S)	Nitric Dioxide (NO_2)

When the GateCycle application calculates the heating value of the fuel, it is assumed that the gas is in the vapor phase at reference conditions. (Reference conditions are the conditions where enthalpy of gas equals 0.0). The GateCycle application uses 60 °F (15.56 °C) as the reference condition.

Table 4- 4 The system data

Case design mode	controlled by equipment input
Properties	
Steam property method	1993 ASME steam property formula
Gas propery method	NASA Properties: S.Gordon, JP McBride
Real gas properties method	Ideal gas - no real gas correction
Reference conditions method	Use default reference condition
System Gas	
Fuel gas composition flag	Mole fractions
Fuel gas heating value flag	Input lower heating value

4.3 Unit modeling

4.3.1 Boiler

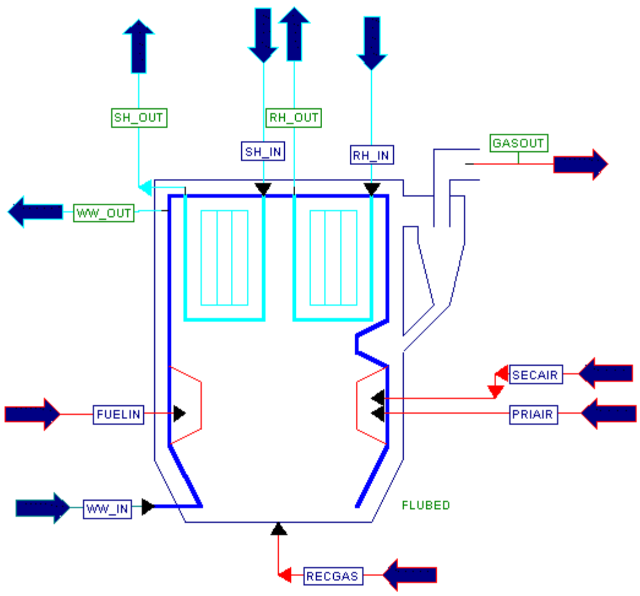

Figure 4- 3 Overview of boiler

The boiler model can be used to design and analyze the performance of fossil-fueled boilers. The FBOILER model can also be used to model externally fired combustors. The fuel streams consist of coal, oil, and any combustible gas fired as a single fuel or as a mixture. Heat released by combustion is transferred to water through the membrane water walls and two placed panel type heat exchangers. The evaporator is not limited to the water walls only; it may also be partially consist of panels. Three heat exchange operations are modeled in the FBOILER. The evaporator (membrane walls) is an optional connection; the two superheating surfaces are optional. When connecting a superheater or reheater, the water walls will have to be connected first. In situations the user might only want to model a superheater but no water walls. For this purpose the inlet flow of the water walls is allowed to be a steam flow.

The design and off-design calculations take into account radiative heat transfer effects. In addition to the gas radiative heat transfer, particle radiation is considered. As an option, bed surface radiation can be considered. Particle convection is also considered as well as gas convection. Finally, water-side heat transfer is taken into account as well. The heat transfer coefficients on the gas-side can be input for either zone.

The main operating parameters are the total fuel or heat input (boiler size), fuel mixture specifications, and excess air specifications, which are used in both design and off-design mode. Radiation of gaseous combustion products such as H_2O and CO_2 is taken into account automatically.

Moreover, the actual operating of coal-fired power plant use the circulating fluidized bed boiler due to constrain of modeling the circulating fluidized bed boiler (CFB) in the GateCycle application, then the fossil boiler is used. The limit of CFB data is the input bed parameter and the design operating of CFB condition from the Foster Wheeler was not shown in the data base. Although, the bed condition is not applied which effect to the ash loss from the combustion then the modeling is maintained the bottom ash temperature and economizer ash temperature at 1000 °C and 199.85 °C respectively. Moreover the bottom ash fraction, economizer ash fraction and unburned carbon fraction in ash is 0.35, 0.05 and 0.01 respectively. The sensible heat of ash temperature and the unburned carbon in ash are the mainly effect to the ash loss. Furthermore, the excess oxygen in the flue gas ensures that the furnace is complete combustion and maintains between 3 to 5%. The realistic combustion the amount of carbon monoxide at the stack before send out the environmental is less than 20ppm. Therefore, the condition of fossil boiler and the circulating fluidized bed boiler is not difference and the radiation modeling in the boiler is as same as.

The boiler of oxy-fuel combustion of coal-fired power plant uses the pure oxygen and the recycle flue gas as feed inlet oxidizer. However, the boiler can be use the air instead of pure oxygen and eliminate the recycle flue gas system in case of air-combustion. In the other hand when the air combustion is applied, the flue gas of the boiler is vented to the atmosphere and then the energy of flue gas loss.

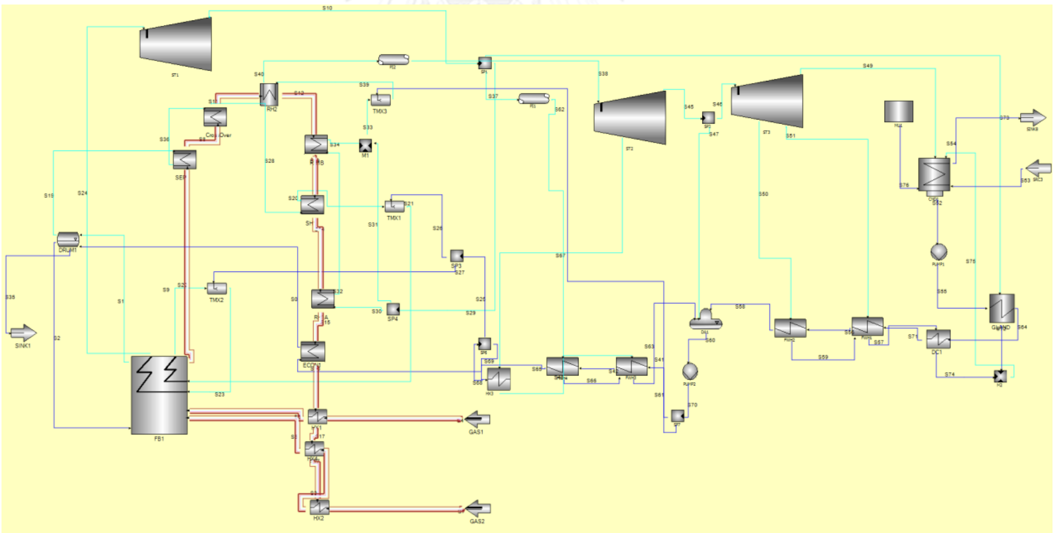

Figure 4- 4 The process flow sheet of air combustion of coal-fired power plant

Connections

There are ports on the FBOILER equipment. These include gas-side ports and water-side ports. The secondary air inlet port must be connected, as must the flue gas outlet. The cycle configured such that the inlet steam flows are saturated or superheated steam. The recycle gas connection used in several ways which depend on the boiler load method is chosen the recycle gas may or may not be allowed to contain any combustibles.

Table 4- 5 Ports on the boiler equipment

Port / Stream	Connected To
Primary Air In (PRIAIR)	(optional) Upstream flow-controlled gas port, usually used for coal pulverization
Secondary Air In (SECAIR)	Upstream flow-controlled gas port
Recycle Gas In (RECGAS)	(Optional) Upstream gas port
Flue Gas Out (GASOUT)	Downstream gas port
Main BFW In (WW_IN)	(Optional) Upstream flow-controlled water port
Main Steam Out (WW_OUT)	(Optional) Downstream steam port
Inlet Steam (SH_IN)	(Optional) Upstream steam port
Exit Steam (SH_OUT)	(Optional) Downstream steam port
Inlet Steam (RH_IN)	(Optional) Upstream steam port
Exit Steam (RH_OUT)	(Optional) Downstream steam port
Inlet Fuel Gas (FUELIN)	(Optional) Upstream fuel gas port

The assumptions of the modeling are

- Modeling based on steady state condition
- Fixed boiler blowdown at 1 kg/s
- Fixed conversion reaction of $CaCO_3$ in limestone 0.9 and $MgCO_3$ 0.999 because furnace temperature is high enough to convert almost 100%
- ST generator efficiency 98%
- Not included aux. load
- Efficiency of pump is fixed 85%
- Model base on steady state condition
- Bottom ash temperature at 1000 °C
- Economizer ash temperature at 199.85 °C
- Bottom ash fraction 0.35 fraction
- Economizer ash 0.05 fraction
- Unburned carbon in ash 0.01 fraction
- Carbonmonoxide fraction in the flue gas is neglected due to normal operating condition is lower than 20 ppm.
- The excess oxygen in the flue gas between 3 to 5%
- The heat input to the boiler is 337,330 and 320 MJ/s in case of BMCR, VWO and TMCR respectively

Table 4- 6 Data input of the boiler

Composition of coal		
Carbon	fraction	0.6118
Hydrogen	fraction	0.047
Oxygen	fraction	0.0882
Nitrogen	fraction	0.034
Sulfur	fraction	0.011
Solid fuel volatile matter fraction	fraction	0.314
Solid fuel cabon fraction	fraction	0.478
Solid fuel ash fraction	fraction	0.088
Solid fuel temperature	°C	25
limit of the exit temperature at the boiler		
Water wall exit temperature	°C	366
Superheater exit temperature	°C	568
Reheater exit temperature	°C	497
Geometry		
Furnace height/Dept		4
Furnace width/Dept		1
Furnace aperture/Dept		1
SH height/Furnace Depth		1.25
RH height/Furnace Depth		1.25
Number of superheater panels		1
Number of reheater panels		1

4.3.1.1. Heat and Mass balance of Boiler

The furnace section of the boiler is the zone that fuel mixes with inlet air and combusts the carbon, hydrogen and sulfur in the fuel with oxygen to form combustion product (carbon dioxide, water and sulfur dioxide). The combustion reactions are assumed to use all of the carbon, hydrogen and sulfur in the fuel exclude the unburned carbon in the ash. The section in the furnace consists of the boiler walls and the section of the main steam superheater and the reheater which get the radiation heat transfer from the hot combustion gases.

<u>The combustion reactions modeled in the furnace are</u>

Combustion of carbon: $$C + O_2 \rightarrow CO_2 \tag{4.1}$$

Mass balance of water: $$2H_2 + O_2 \rightarrow 2H_2O \tag{4.2}$$

Mass balance of sulfur: $$S + O_2 \rightarrow SO_2 \tag{4.3}$$

The gas composition at the exhaust gas of the furnace can be calculated by using the mass balance calculation of each element flowing into or out of the furnace:

$$\text{Outlet flow} = \text{Inlet flow} + \text{Product} - \text{Reactants} \tag{4.4}$$

where Outlet flow is the mass flow rate of each substance from the furnace**,** Inlet flow is the mass flow rate of each substance into the furnace**,** Product is the rate that mass of each substance is generated in the combustion fuel and Reactant is the rate that mass of each substance is consumed in the combustion reaction.

The mass balance calculation of each element must be applied separately for each element that flow into the furnace. The substance is included oxygen, nitrogen, carbon dioxide, fuel, sulfur and water. The association between the mass flow rate of the substance and the mole fraction of the substance in a gas mixture is shown in the equation (4.5)

Mass flow of the substance in a gas mixture

$$w_i = X_i \frac{M_i}{M_{gas}} W_{gas} \tag{4.5}$$

where W_i is the mass flow rate of the substance i, such as O_2, N_2, CO_2 or H_2O, W_{gas} is the mass flow rate of the gas mixture, X_i is the mole fraction (or volume fraction for a gas) of the substance i in the gas mixture, M_i is the molecular weight of the substance i and M_{gas} is the molecular weight of the gas mixture.

Oxygen Mass Balance

$$X_{O_{2flue}}\frac{M_{O_2}}{M_{gas_{flue}}}W_{gas_{flue}} = X_{O_{2in}}\frac{M_{O_2}}{M_{gas_{in}}}W_{gas_{in}} + \frac{\%O}{2}W_{fuel} - \frac{M_{O_2}}{M_C}(C_b)W_{fuel} - \frac{M_{O_2}}{2M_{H_2}}(\%H)W_{fuel} - \frac{M_{O_2}}{M_S}(\%S)W_{fuel} \quad (4.6)$$

$$C_b = (\%C)_{fuel} - (\%C)_{ash}(\%Ash)_{fuel} \quad (4.7)$$

where X_{O2flue} is the mole fraction (volume) of oxygen at the flue gas exit of furnace, X_{O2flue} is the mole fraction (volume) of oxygen at air inlet to the furnace, $M_{gasflue}$ is the molecular weight of the combustion gas at the flue gas exit, M_{gasin} is the molecular weight of the oxygen in the air inlet to the furnace, W_{fuel} is the mass flow rate of the fuel, $W_{gasflue}$ is the mass flow rate of gas mixture at the flue gas exit of furnace, W_{gasin} is the mass flow rate of the oxygen in the air inlet to the furnace, C_b is the mass of carbon burned per unit fuel mass , %H is mass fraction of hydrogen in the fuel, except the hydrogen in the moisture in the fuel, $\%H_2O$ is mass fraction of moisture in the fuel, %S is mass fraction of sulfur in the fuel, %O is mass fraction of oxygen in the fuel, $(\%C)_{fuel}$ is the mass fraction of carbon in the fuel, $(\%C)_{ash}$ is the mass fraction of unburned carbon in the ash and $(\%Ash)_{fuel}$ is the mass fraction of ash in the fuel .

Nitrogen Mass Balance

$$X_{N_{2flue}} \frac{M_{N_2}}{M_{gas_{flue}}} W_{gas_{flue}} = X_{N_{2in}} \frac{M_{N_2}}{M_{gas_{in}}} W_{gas_{in}} - (\%N)W_{fuel} \quad (4.8)$$

Carbon dioxide mass balance

$$X_{CO_{2flue}} \frac{M_{CO_2}}{M_{gas_{flue}}} W_{gas_{flue}} = X_{CO_{2in}} \frac{M_{CO_2}}{M_{gas_{in}}} W_{gas_{in}} - \frac{M_{CO_2}}{M_C} (C_b) W_{fuel} \quad (4.9)$$

Water Vapor mass balance

$$X_{H_2O_{flue}} \frac{M_{H_2O}}{M_{gas_{flue}}} W_{gas_{flue}} = X_{H_2O_{in}} \frac{M_{H_2O}}{M_{gas_{in}}} W_{gas_{in}} - \frac{M_{H_2O}}{2M_{H_2}} (\%H) W_{fuel} - (\%H_2O) W_{fuel}$$

(4.10)

Sulfur Dioxide Mass balance

$$X_{SO_{2flue}} \frac{M_{SO_2}}{M_{gas_{flue}}} W_{gas_{flue}} = X_{SO_{2in}} \frac{M_{SO_2}}{M_{gas_{in}}} W_{gas_{in}} - \frac{M_{SO_2}}{M_S} (\%S) W_{fuel} \quad (4.11)$$

Ash Mass Balance

$$W_{gas_{flue}} + W_{ash} = W_{gas_{in}} + W_{fuel} \quad (4.12)$$

Molecular weight of a Gas mixture

$$\mathrm{M_{gas}} = \Sigma \mathrm{X_i M_i} \qquad (4.13)$$

The furnace energy balance that outlet flow rate of the energy from the furnace must equal the inlet flow rate of energy into the furnace. The control volume consists of the furnace, the superheater, the reheater and the furnace walls. The furnace control volume did not include the reheater, superheater, and the furnace walls.

Energy Balance on Furnace control volume

$$h_{gas}w_{gas_{flue}} + Q_{wall} + Q_{SH} + Q_{RH} + Q_{rad} + (h_{ash} + (\%C)H_C)w_{ash} =$$

$$C_{P_{in}} w_{gas_{in}} \left(T_{gas_{in}} - T_{gas_{ref}}\right) + (h_{fuel} + LHV)w_{fuel} \qquad (4.14)$$

Energy Balance of radiant main steam superheater (SH)

$$Q_{SH} = \left(h_{SH_{out}} - h_{SH_{in}}\right)w_{SH} \qquad (4.15)$$

Energy Balance of radiant reheat steam superheater (RH)

$$Q_{RH} = \left(h_{RH_{out}} - h_{RH_{in}}\right)w_{RH} \qquad (4.16)$$

Energy Balance of water wall

$$Q_{wall} = \left(h_{drum}w_{drum} + h_{bdown}w_{bdown} - h_{wall_{in}}w_{wall_{in}}\right) \qquad (4.17)$$

where $h_{gasflue}$ is the enthalpy of the gas in the flue gas, $W_{gasflue}$ is the gas flow rate of flue gas, T_{gasin} is the temperature of the gas at the air inlet, T_{gasref} is the reference gas temperature where the enthalpy equal to zero, h_{ash} is the enthalpy of the ash outlet the furnace, W_{ash} is the mass flow rate of the ash outlet the furnace, LHV is the lower heating value of the fuel, $\%C_{ash}$ is the mass fraction of carbon in the ash (pounds of carbon per pound of ash), h_c is the heating value of carbon in the ash, Q_{wall} is the heat transfer rate to the furnace walls, Q_{SH} is the heat transfer rate to the main steam superheater section in the furnace, Q_{RH} is the heat transfer rate to the reheat steam superheater section in the furnace, Q_{rad} is the radiation heat transfer rate to the environment, h is the enthalpy of the water/steam at the inlet and/or outlets of the heat exchangers, w is the mass flow rate of the water/steam at the inlet and/or outlets of the heat exchangers which control volume as shown in Figure 4-5.

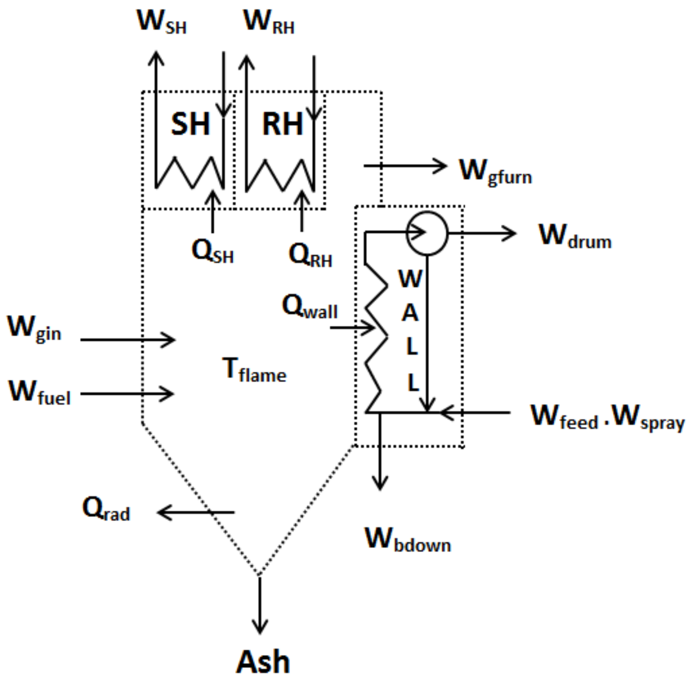

Figure 4- 5 Control volumes for furnace mass and energy balances

The ash outlet the furnace is divided into ash exit streams. An ash mass fraction and temperature is associated with ash flow for calculate the ash enthalpy. Mass fraction of ash and temperature at each boiler exit position need input for analysis. These value is not measure and then be assumed.

Enthalpy of boiler ash

$$h_{ash} = C_{P1}F_1\left(T_1 - T_{ref}\right) + C_{P2}F_2\left(T_2 - T_{ref}\right) + C_{P3}F_3\left(T_3 - T_{ref}\right) \tag{4.18}$$

where C_{Pi} is the specific heat of the ash leaving the boiler at position i, F_i is ash mass fraction of the ash leaving the boiler at position i, T_i is the temperature of the ash leaving the boiler at position i, T_{ref} is the reference temperature at the enthalpy equals zero.

Specific heat of a gas mixture

$$C_{P_{gas}} = \sum_{gas} X_i \frac{M_i}{M_{gas}} C_{Pi} \tag{4.19}$$

where C_{Pi} is the specific heat of the substance i, C_{Pgas} is the specific heat of the gas mixture, X_i is the mole fraction of the substance I in the gas mixture, M_i is the molecular weight of substance i, M_{gas} is the molecular weight of the gas mixture

Therefore;

$$C_{P_{gas}} = X_{N_2}\frac{M_{N_2}}{M_{gas}}C_{PN_2} + X_{O_2}\frac{M_{O_2}}{M_{gas}}C_{PO_2} + X_{CO_2}\frac{M_{CO_2}}{M_{gas}}C_{PCO_2} + X_{H_2O}\frac{M_{H_2O}}{M_{gas}}C_{PH_2O} + X_{SO_2}\frac{M_{SO_2}}{M_{gas}}C_{PSO_2} \tag{4.20}$$

Moreover, the furnace heat balance analysis can be determined the outlet gas conditions from the furnace given the inlet air and fuel flows. The outlet temperature of the furnace gas can be calculated from the enthalpy and specific heat:

Furnace exit gas temperature

$$T_{gas_{furn}} = \frac{h_{gas_{furn}}}{C_{P_{furn}}} + T_{gas_{ref}} \quad (4.21)$$

The furnace exit gas temperature is the temperature of the combustion gas after transferring heat to the radiant heat transfer section of the boiler which consists of superheater, reheater and water wall. Furthermore, the important parameter of the boiler performance is the adiabatic flame temperature which is combusts gas and there is no heat transfer out of the furnace to the steam/water flows in the radiant furnace walls, reheater and superheater. A furnace energy balance which assumed no heat transfer to the furnace walls, reheater and superheater is used to calculate the adiabatic temperature.

Energy Balance for adiabatic flame temperature

$$h_{flame}w_{furn} + (h_{ash} + (\%C)_{ash}H_C)w_{ash} = h_{gas_{in}}w_{gas_{in}} + (h_{fuel} + LHV)w_{fuel}$$

(4.22)

Therefore the flame temperature can be calculated from the flame enthalpy:

$$T_{flame} = \frac{h_{flame}}{C_{P_{furn}}} + T_{gas_{ref}} \quad (4.23)$$

The steam temperature at the inlet to the radiant superheater and reheater is important to measure. Although the temperature is estimated during the overall plant heat balance analysis but that is impossible to separate the degradation both convective heat exchange units and the radiant heat exchange units without the measured temperature between the relate regions.

The heat exchange units analysis of the water wall requires value for wall furnace and exit enthalpy which is difficult to know if the control volume included only the tube along the walls of the boiler. The steam/water enthalpy at outlet tube did not know and the flow rate through the boiler is depended on the recirculating of water from the steam drum. This trouble can be solved by including the steam drum and water recirculating path from the drum to the wall as a part of control volume for the furnace wall heat exchange units. Then the outlet enthalpy from the wall is saturated steam at the drum pressure, and the outlet flow rate from the wall control volume is the steam production in the drum.

Heat balance analysis of boiler Convective heat exchange units

The convective heat exchange units surface in the boiler heat balance model are the second main superheater (SH2), the second reheater(RH1) and the economizer(ECON). The aim of the heat balance analysis for the convective heat units is to calculate the heat transfer rate to each unit. The gas temperature will be used to predict the expected heat transfer rate in each heat exchanger.

<u>Gas side energy balance</u>

$$Q = C_{Pgas}(T_{gas\ in} - T_{gas\ out})w_{gas} \qquad (4.24)$$

<u>Steam/water side energy balance</u>

$$Q = (h_{H_2\ O_{out}} - h_{H_2\ O_{in}})W_{H_2O} \qquad (4.25)$$

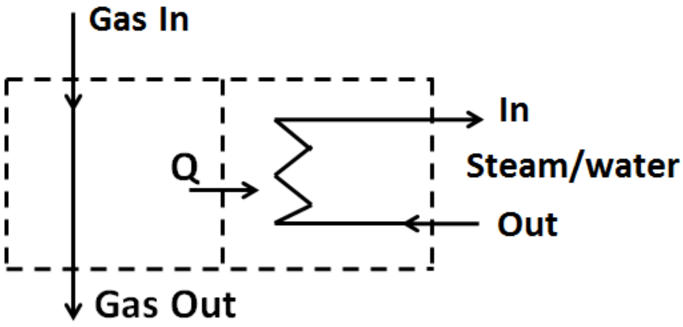

Figure 4- 6 The control volume for convective heat exchange units in the boiler

4.3.1.2. Boiler Performance

1. Boiler efficiency

The aim of the boiler in the Rankine cycle power plant is to convert the energy in the fuel to steam energy that is use for generating electricity. The efficiency of the boiler is determined as the fraction of the total energy input into the boiler that is converted to use steam energy.

$$\text{boiler Efficiency} = \frac{\text{Energy to useful steam production}}{\text{Boiler Energy input}} \tag{4.26}$$

Then the useful energy for steam production is equal to the energy transferred to the steam/water, the boiler efficiency is equal to the energy transferred to the steam/water divided by the energy input to the boiler:

<u>Boiler efficiency (input-output method):</u>

$$\text{boiler Efficiency} = \frac{w_{sh}h_{sh}+w_{rh}h_{rh}-w_{feed}h_{feed}-w_{crh}h_{crh}}{w_{fuel}\,(LHV+h_{fuel})+w_{air}h_{air}+W_{fan}} \tag{4.27}$$

where w is the mass flow rate, with the below subscripts, sh is the mains steam at the superheater exit, rh is the reheat steam at the exit of the reheat superheater, feed is inlet feed water which include water in the desuperheating sprays, crh is cold reheat steam input to the boiler, air is the inlet air to the boiler, fuel is the fuel input to the boiler, h is the enthalpy (BTU/lbm or kJ/kg), LHV is the lower heating value of the fuel, W_{fan} is the power input to the boiler fans and auxiliaries load.

The input-output method is not the preferred method to calculate boiler efficiency due to the measurement of fuel flow rate is not accurately. Then the loss method is the alternate expression for boiler efficiency.

$$\text{boiler Efficiency} = \frac{\text{Boiler energy input} - \text{Boiler lost energy}}{\text{Boiler Energy input}} \tag{4.28}$$

$$\text{boiler Efficiency} = 1 - \frac{\text{Boiler lost energy}}{\text{Fuel Energy input} + \text{Other energy inputs}} \tag{4.29}$$

$$\text{boiler Efficiency} = 1 - \frac{\text{Losses}}{\text{HHV} + \text{credits}} \tag{4.30}$$

where Losses are the total energy outflows other than use of steam per unit fuel flow , HHV is the fuel higher heating value (BTU/lbm) or (kj/kg), Credits are the energy that flows into the boiler other than fuel energy per unit fuel flow.

The energy losses from a boiler are from these causes: the energy of the flue gas exiting the boiler, the energy that contain in ash and the radiation heat transfer loss to the environment.

Boiler losses:

$$\text{Losses} = \text{Losses}_{\text{fluegas}} + \text{Losses}_{\text{ash}} + \text{Losses}_{\text{radiation}} \quad (4.31)$$

where $L_{fluegas}$ is the energy lost in the flue gas per unit fuel flow, L_{ash} is the energy lost in the ash per unit fuel flow, $L_{radiation}$ is the energy lost because the heat transfer from the boiler to the environmental.

The losses of flue gas energy are the largest loss. The energy of the flue gas per unit fuel flow is a function of flue gas temperature which effect to the enthalpy of flue gas and the flue gas oxygen content which is the indicator of the excess air flow in the flue gas.

2. Theoretical Air

The convention boiler use air to complete the combustion. The amount of air require to complete combust the fuel is the theoretical air and the additional amount of air that confirm there are no fuel-rich zone is the excess air. The requirement of combustion chemical reactions and the fuel combusted with that oxygen is the stoichiometric combustion. The amount of air and fuel are the theoretical air and theoretical fuel respectively. The air that introduced to the boiler supplies the oxygen. Under the condition of stoichiometric combustion there is no oxygen in the flue gas and all of the carbon, hydrogen and sulfur in the fuel consumed in the combustion process.

$$\text{Theoretical Air} = \left(\frac{w_{\text{air}}}{w_{\text{fuel}}}\right)_{\text{stoichiometric}} \quad (4.32)$$

The combustion reactions modeled in the furnace are

Combustion of carbon: $C + O_2 \rightarrow CO_2$ (4.33)

Mass balance of water: $2H_2 + O_2 \rightarrow 2H_2O$ (4.34)

Mass balance of sulfur: $S + O_2 \rightarrow SO_2$ (4.35)

$$\text{Theoretical Air} = \frac{w_{air_{stoichiometric}}}{w_{fuel}} \quad (4.36)$$

$$\text{Theoretical Air} = \frac{M_{air}}{X_{O_{2_{air}}} M_{O_2}} [\frac{M_{O_2}}{M_C}(\%C) + \frac{M_{O_2}}{2M_{H_2}}(\%H) + \frac{M_{O_2}}{M_s}(\%S) - \frac{(\%O)}{2} \quad (4.37)$$

where Theoretical air is the mass of air per mass of fuel required for stoichiometric combustion, X_{O2}air is the volume fraction of oxygen in the inlet air (or gas mixture), M_{O2} is the molecular weight of oxygen that equal to 32, M_{air} is the molecular weight of inlet air that equal to 28.97 for standard air or of the inlet gas mixture that contain oxygen, M_{H2} is the molecular weight of hydrogen that equal to 2, M_C is the molecular weight of oxygen that equal to 12, %C is the mass fraction of carbon in the fuel, %H is the mass fraction of hydrogen in the fuel, %S is the mass fraction of sulfur in the fuel, %O is the mass fraction of oxygen in the fuel

When the theoretical airs were supplied and all of the fuel was combusted, the oxygen content in the flue gas should be zero. The excess air is introduced to the boiler then the oxygen content of the flue gas increases.

$$\text{Excess Air} = \frac{w_{air} - w_{air_{stoichiometric}}}{w_{air_{stoichiometric}}} \tag{4.38}$$

<u>Excess air calculated from oxygen volume fractions:</u>

$$\text{Excess Air} = \frac{X_{O_{2flue}}}{X_{O_{2air}} - X_{O_{2flue}}} \tag{4.39}$$

where Excess air is the additional airflow added to the boiler in addition to the theoretical air, X_{O2flue} is the volume fraction of oxygen in the flue gas, X_{O2air} is is the volume fraction of oxygen in the ambient air

<u>Air flow to the boiler</u>

$$w_{air} = \text{Theoretical air } (1 + \text{Excess air}) w_{fuel} \tag{4.40}$$

<u>Flue gas flow rate</u>

$$w_{flue} = w_{air} + w_{fuel} \tag{4.41}$$

3. Boiler Losses

Boiler loss is the all of the energy outlet from the boiler other than the energy converted to the steam produced in the boiler that sent to the steam turbine for generating electricity. Therefore the steam that use to preheat air or fuel sent into the boiler is not considered. The energy lost from the boiler consists of these energy flows consists of flue gas energy, energy in the ash and radiation heat transfer loss to the environmental. The energy of flue gas outlet of the boiler is equal to the gas flow rate multiplied by the enthalpy and plus the heating value of any unburned chemical in the flow

$$\text{Flue gas energy} = w_{flue}h_{flue} + w_{co}H_{co} + w_{CHx}H_{CHx} + w_{H2}H_{H2} \quad (4.42)$$

where h is the enthalpy (BTU/lbm or kJ/kg), H is the heating value of gas when combusted (BTU/lbm or kJ/kg)

The ash energy is produced from the thermal (sensible) energy of the ash because its temperature, plus the chemical energy in the ash due to unburned carbon:

$$\text{Ash energy} = w_{ash}h_{ash} + w_{c}H_{c} \quad (4.43)$$

Radiation heat transfer to the environment is increased by the temperature difference between the boiler wall and the ambient air. Due to the wall temperature and heat transfer coefficient did not know then heat transfer loss to the environmental is usually modeled as a percent of the fuel input energy

4. Flue gas loss

The largest loss of energy from the boiler is that lost with the outlet flue gas. All of the carbon monoxide, hydrocarbons and hydrogen in the fuel are completely combusted in the furnace, and then the flue gas energy is equal to its flow rate multiplied by the enthalpy.

$$L_{fluegas} = \frac{w_{flue} h_{flue}}{w_{fuel}} \tag{4.44}$$

where L_{flue} gas is the energy loss per unit fuel flow associated with the flue gas, W_{flue} is the mass flow rate of the flue gas, W_{fuel} is the mass flow rate of the fuel, H_{flue} is the enthalpy of the fuel (BTU/lbm or kJ/kg).

5. Loss caused by ash

$$L_{fluegas} = \frac{w_{ash}}{w_{fuel}} (h_{ash} + (\%C)_{ash} H_c) \tag{4.45}$$

where $\frac{w_{ash}}{w_{fuel}}$ is the mass of ash generated per unit mass of fuel, $(\%C)_{ash}$ is the mass of carbon per unit mass of ash produced, H_{ash} is the enthalpy of the ash, equal to the specific heat multiplied by the temperature, H_C is the heating value of carbon in the ash

6. Loss caused by radiation

Radiation loss is modeled as a function of the fuel energy.

$$L_{Radiation} = F_{Radiation} HHV \tag{4.46}$$

where $L_{radiation}$ is the boiler energy loss per unit fuel flow due to radiation, $F_{radiation}$ equals the fraction of boiler energy lost to the environment by heat transfer, HHV is the higher heating value of the fuel.

4.3.2 Steam turbine

The Steam turbine (ST) equipment includes up to four uncontrolled extractions per section. The ST model can be calculate design and off-design efficiencies based on published GE steam turbine performance data which include the modeling of governing stage and exhaust-loss effects. For off-design steam turbine cases, Stodola ellipse calculations are used to define the extraction pressures (all internal ST pressures) and the inlet pressure for sliding-pressure operation.

The steam turbine inputs and calculations are based on a section-by-section configuration of the steam turbine which is directly in line with how a steam turbine manufacturer designs and assembles turbines. The ST calculation methodology assumes that your ST design point is at full-flow valves-wide-open (VWO) conditions.

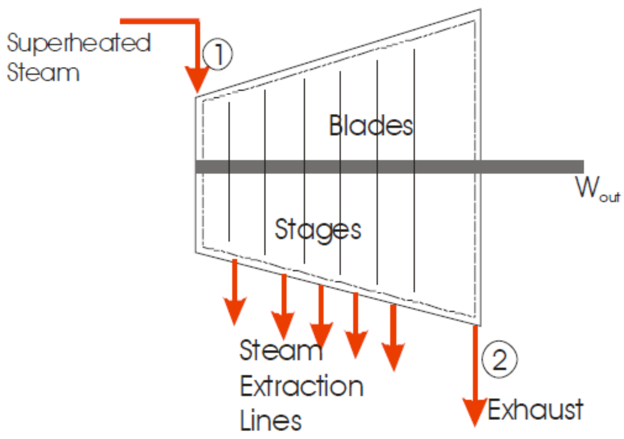

Figure 4- 5 Overview of Steam turbines

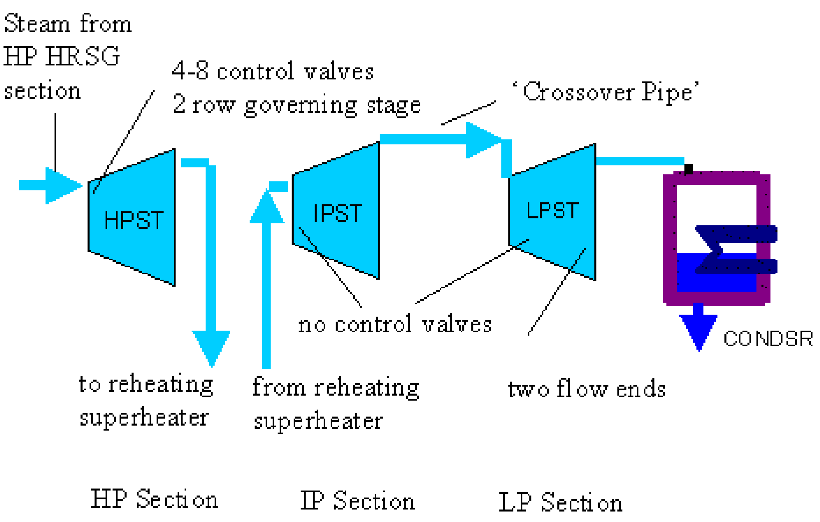

Figure 4- 6 Steam turbine Section by Section Modeling

Connections

There are multiple ports on steam turbine equipment which consists of the inlet and exit steam ports (STM_IN and STMOUT) and the uncontrolled extraction steam ports (EXTRC1-EXTRC4). Three admission ports can connect to upstream steam ports, and two shaft ports can be connected to mechanical work ports on other rotating equipment such as pumps.

The cycle configured such that the inlet steam is always saturated vapor or superheated steam. The inlet steam port is connected to the exit of a superheater or another steam turbine section, and the exit steam port to another steam turbine section or a condenser. The extraction ports are often connected to the deaerators .

Table 4- 7 Ports on the steam turbine equipment

Port / Stream	Connected To	Comment
Steam Inlet (STM_IN)	Upstream steam port	Required
Main Out (STMOUT)	Downstream steam port	Required
First Extraction (EXTRC1)	Downstream steam port	Optional
Second Extraction (EXTRC2)	Downstream steam port	Optional
Third Extraction (EXTRC3)	Downstream steam port	Optional
Fourth Extraction (EXTRC4)	Downstream steam port	Optional
First Shaft	Mechanical work port	Optional
Second Shaft	Mechanical work port	Optional
First Admission	Upstream steam port	Optional
Second Admission	Upstream steam port	Optional
Third Admission	Upstream steam port	Optional

Steam turbine converts the enthalpy of the working fluid to mechanical work. The steam turbine consists of many stages which typically are the stationary nozzles and moving blades. Each stage is designed to convert the amount of the thermal energy into mechanical energy.

The modeling of steam turbine, the input data of high pressure, intermediate pressure and low pressure is shown in below table. The input data consists of outlet pressure and maximum of inlet temperature.

Table 4- 8 Data input of the steam turbine

HP turbine outlet pressure	bar	40
HP turbine maximum inlet temperature	°C	600
IP turbine outlet pressure	bar	10.2
IP turbine maximum inlet temperature	°C	565.56
LP turbine outlet pressure	bar	0.07
LP turbine maximum inlet temperature	°C	565.56

The analysis of turbines uses the first law by assuming that the turbine is operated in the steady state. Therefore the mass flow rate keeps constant throughout. Moreover, assuming that the change in enthalpy is larger, much larger than the change in the kinetic and potential energy, so the first law becomes:

$$W_{t,out} = Wsteam(h_1 - h_2) \tag{4.47}$$

Normally, the turbine has the extraction stage then the mass flow rate of steam decreases while it is from the first stage to the final stage. Then the turbine work out, have to consider each stage as a single turbine as below equation.

$$W_{t,out} = \sum_i W_{stage,i} = \sum_i m_i (h_{i,in} - h_{i,out}) \tag{4.48}$$

The performance of turbine measures by turbine efficiency. The ideal steam turbine would have no losses due to leakage, friction or the turbulence in the steam path such as the turbine would convert all of the energy in the steam to the mechanical power. The steam expansion through as the ideal turbine is an isentropic expansion. The isentropic efficiency is determined as the ratio of the actual power generating to the power which would be generated in an isentropic expansion.

Isentropic Efficiency

$$\text{Isentropic Efficiency} = \frac{h_{in} - h_{out}}{h_{in} - h_{out,ideal}} \tag{4.49}$$

Where h_{in} is the steam enthalpy at the inlet to the steam turbine, h_{out} is the steam enthalpy at the outlet to the steam turbine, $h_{out,ideal}$ is the isentropic (ideal) steam enthalpy at the outlet of the steam turbine.

The isentropic enthalpy is the enthalpy that would happen when the entropy of the steam remained constant while the steam expands since the inlet pressure to the outlet pressure.

4.3.3. Feed water heater

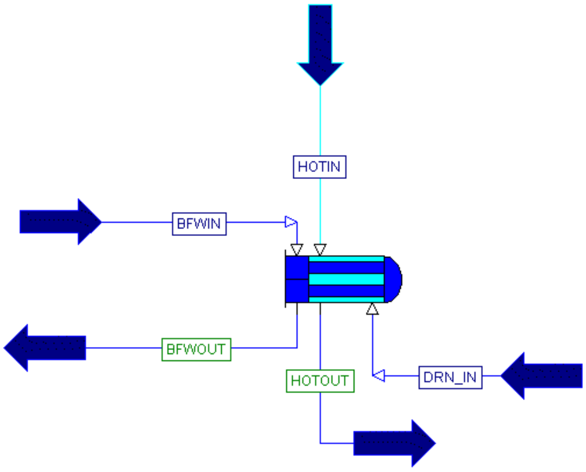

Figure 4- 7 overview of the feed water heater

The feed water heater models where condensing steam is used to heat up a liquid water stream. The key operating parameters include the terminal temperature difference (TTD), drain-cooler approach temperature (DCA), and pressure drops.

Connections

There are six ports on a feedwater heater. The four basic ports are the inlet and exit ports for both the hot-side and cold-side. The fifth port is the optional drain inlet port and the sixth (not shown) is an optional auxiliary steam/water inlet port.

Both cold-side ports and the hot-side outlet ports should be connected to water ports on other equipment. The hot inlet port should be connected to a steam port on equipment (usually an extraction from a steam turbine). The optional drain inlet and auxiliary inlet ports can be connected to either water or steam ports. Generally, the boiler feedwater stream will be connected to the cold ports, the hot inlet port will be connected to a steam turbine extraction port and the drain inlet will be connected to the hot outlet port of another higher pressure feedwater heater.

Table 4- 9 Ports on the feed water heater equipment

Port / Stream	Connected To	Comment
Hot Side Inlet (HOTIN)	Steam port	Required
Hot Side Exit (HOTOUT)	Water port	Required
Cold Side Inlet (BFWIN)	Water port	Required
Cold Side Exit (BFWOUT)	Water port	Required
Drain Inlet (DRN_IN)	Water/steam port	Optional
Aux. Inlet	Water/steam port	Optional, not shown above

4.3.3.1 Feedwater heater heat-balance analysis

The law of conservation of mass as applied to a feedwater heater states that the inlet flow rate of the feedwater to the feedwater heater is equal to the outlet flow rate of feedwater.

Water-side Mass Balance

$$W_{f,in} = W_{f,out} \quad (4.50)$$

where W_{fin} is the mass inlet flow rate of feed water to the feedwater heater, W_{fout} is the mass outlet flow rate of feed water to the feedwater heater.

Water-Side Energy balance

$$h_{f,in}W_{f,in} + Q_{fwh} = h_{f,out}W_{f,out} \quad (4.51)$$

where $h_{f,in}$ is the enthalpy of the feedwater at the inlet flow port, $h_{f,out}$ is the enthalpy of the feedwater at the outlet flow port, Q_{fwh} is the heat transfer rate (duty) from the steam-side to the water side

Steam-side Mass Balance

$$W_{s,in} + W_{d,in} = W_{d,out} \tag{4.52}$$

where $W_{s,in}$ is the mass inlet flow rate of extraction steam into the feedwater heater, $W_{d,in}$ is the mass inlet flow rate of drain water from a higher pressure feedwater heater, $W_{d,out}$ is the mass outlet rate of drain water out of the feedwater heater

Steam-side energy balance

$$h_{s,in}W_{s,in} + h_{d,in}W_{d,in} = h_{d,out}W_{d,out} + Q_{fwh} \tag{4.53}$$

where $h_{s,in}$ is the enthalpy of the extraction steam at the inlet flow port, $h_{d,in}$ is the enthalpy of the inlet drain water, $h_{d,out}$ is the enthalpy of the outlet drain water.

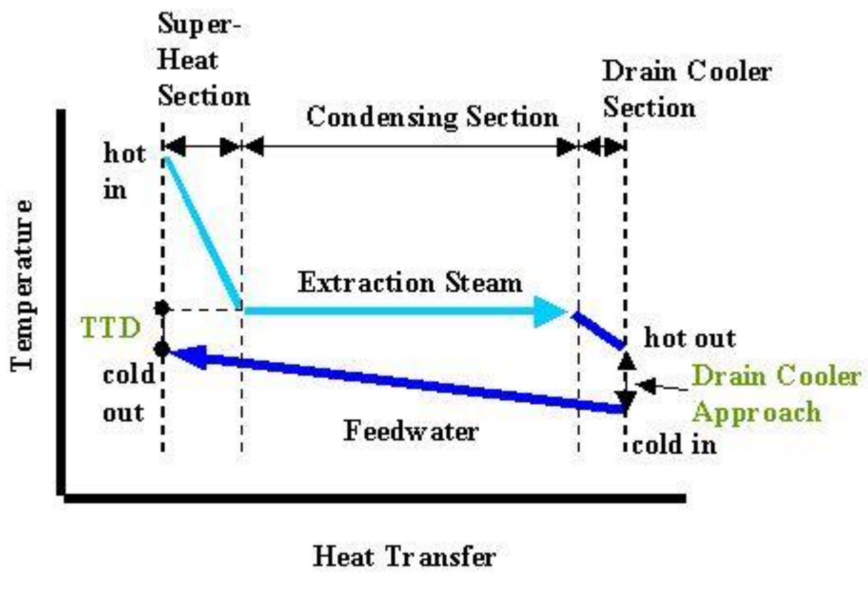

Figure 4- 8 Temperature profile within a feedwater heater

4.3.4. Economizer

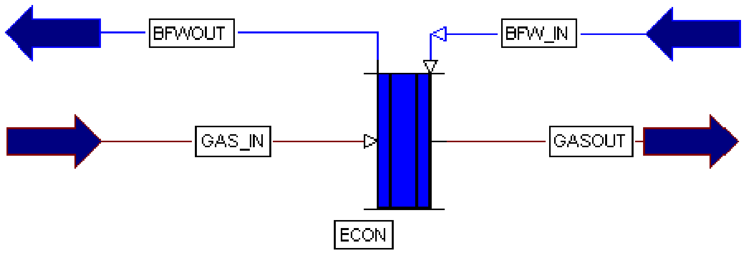

Figure 4.9 Overview of economizer

The economizer is a heat exchanger used to extract energy from a hot gas stream and transfer it to the liquid water stream to heat up the water. In a general, heat-recovery steam generator, an economizer consists of a series of finned or bare tubes through which water passes, around the outside of which passes the hot gas flow. Important operating parameters include the pressure drops of the water passing through the tubes and the gas flowing around the tube banks, the exit temperatures of the water and the gas streams, and the effectiveness of the heat exchanger (a ratio of the actual heat transfer in the economizer to the maximum possible heat transfer).

Connections

There are four ports on economizer equipment which consists of the inlet and exit water and gas ports. The cycle should be configured such that the inlet water will always be subcooled liquid water. Normally, the inlet water port will be connected to the exit of another economizer, a pump, or a deaerator, and the exit water port will be connected to the inlet water port of an evaporator, another economizer or the inlet boiler feedwater port of a deaerator.

Table 4- 10 Ports on the economizer equipment

Port / Stream	Connected to	Comment
Inlet Gas GAS_IN)	Upstream gas port (hot inlet)	Required
Exit Gas (GASOUT)	Downstream gas port	Required
Inlet Water (BFW_IN)	Upstream subcooled water port (cold inlet)	Required
Outlet Water (BFWOUT)	Downstream water port	Required

4.3.4.1 Economizer Performance

The temperature profile (temperature vs heat transferred) across the gas and water sides of an economizer is shown the important parameter of economizer performance that is the amount of subcooling at the water exit. Subcooling is the temperature difference between the water outlet and the saturation of the water at the exit pressure of the economizer. The lower subcooling, the higher efficient the economizer is. When the subcooling decreases, the possibility of the economizer steaming at off-desing operating condition increases. Steaming appears when the economizer exit temperature reaches the saturation temperature. Steaming economizer can cause erostion, stress and operational problems within the economizer. Generally, the economizer is designed for 10–20 °F of subcooling at the exit to maintain the suitable steaming conditions.

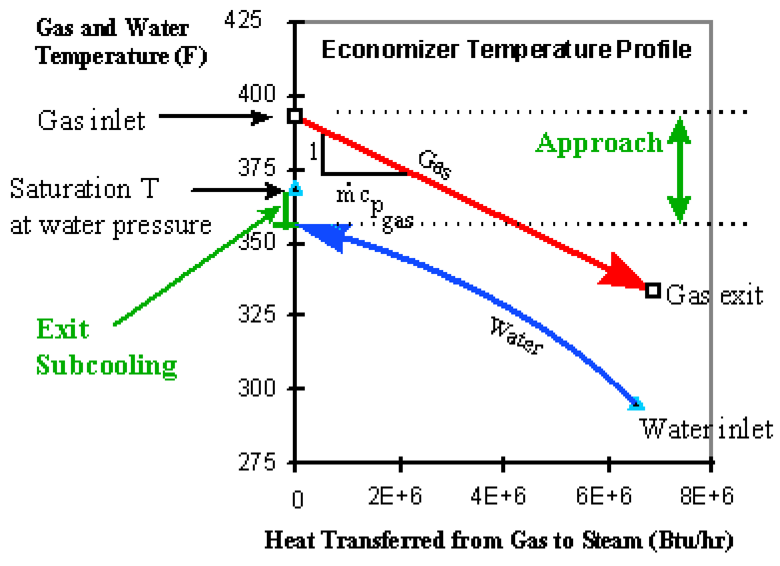

Figure 4- 7 Economizer Temperature Profile

4.4 Model validation

The model of oxy-fuel combustion of coal-fired power plant which mentioned in the previous section is ensured by the validation between simulation and design operating condition from the owner of boiler that receive since coal-fired power plant was commissioning. Due to the limit of the data of operating condition of the oxy-fuel combustion of coal fired power plant. Therefore the air-combustion is used to verify the model by validation between simulation and design operating condition.

For the purpose of this section, the calculation of the heat and mass balance is evaluated using Gate Cycle formula software. This software application can be enable the steady state analysis of thermal power plant to be evaluated presenting the, heat and mass balance for a power plant in the form of a configuration model. This software is used to forecast both design and off-design performance of the coal-fired power plants. There are some applications that used the Gate Cycle to calculate and evaluate systems based upon their designed operating conditions and differing values of system parameters.

The model validation of the efficiency is derived by using the Gate Cycle model. Reference data from the heat and mass balance all 3 cases are based upon the design operating condition established during the commissioning of the power plant.

The object of these 3 conditions of the power plant model validation cases is to confirm that the model can operate under these various un-rigid conditions steady state.

Case I: BMCR

Case II: VWO (Valve Wide Open)

Case III: 100% TMCR

The operating is the maximum continuous rating. BMCR is the Boiler maximum continuous rating and TMCR is the turbine maximum continuous rating. The boiler maximum continuous rating is the ability of steam boiler to produce and provide the stated quantity of steam continually and easily with no all degradation effects such as overloading, slagging or overheating which depend on the principal of boiler and its components. The VWO is valves wide open and at normal pressure allows the steam turbine to exceed turbine maximum continuous rating by 5-10 percent. The operating full load is not kept which implies the turbine has reached it purposed the maximum. The base load is also a flexible amount and implies the turbine will not be operated below that condition. The boiler maximum continuous rating must be at least turbine maximum continuous rating but should have allowance the loss of turbine efficiency which requires more steam to arrive turbine maximum continuous rating.

The owner of boiler is designed the boiler maximum continuous rate (BMCR) which maintains heat input (HHV) at 337 MJ/s. The coal composition, coal heating value and coal flow rate are constant. Then heat input of boiler can vary from 337 MJ/s to 330 MJ/s. the heat input can reduce to 320 MJ/s when valve wide open and turbine maximum continuous rate.

Results from Gate Cycle are compared to current operating conditions and design condition from the owner of the power plant. These conditions are used to verify the result of the Gate cycle. Design-conditions of power plant and results of the Gate Cycle are based upon design-conditions at the condition of boiler maximum continuous rate (BMCR), the condition of the steam turbine at the valve wide open(VWO) and the condition of turbine maximum continuous rate(TMCR). The pressure, temperature and flow rate of input and output of boiler system are shown in the Table 4-11. Due to the result of the owner is the confidential result then the data is not shown in details. The result of Gate Cycle and designed boiler maximum continuous rating (BMCR), the condition of the steam turbine at the valve wide open(VWO) and the condition of turbine maximum continuous rate(TMCR) are comparable with a maximum error of approximately 1.56% As shown in Table 4-12.

Table 4- 11 The input and output parameter of boiler

Property	Unit	Value
Plant Net Power	MW	126.3458
Boiler feed water flow	kg/hr	471768.8
Adiabatic flame temperature	C	1675.854
Primary Air Inlet Flow	kg/hr	315708.6
Secondary Air Inlet Flow	kg/hr	243271.8
Superheater Inlet Flow	kg/hr	360883.8
Superheater Inlet Pressure	bar	182.5575
Superheater Inlet Temperature	C	483
Superheater Outlet Flow	kg/hr	360883.4
Superheater Outlet Pressure	bar	177.4459
Superheater Outlet Temperature	C	568

Table 4- 12 Power and efficiency of design operating condition case

Property	Unit	BMCR		
		Design	GateCycle	Error [%]
SH outlet steam flow	kg/h	362088	360883	-0.33
SH outlet steam flow	kg/s	100.58	100.25	-0.33
Net power	MW	126.47	126.35	-0.1
Heat input (HHV)	MJ/s	337	337	0
boiler efficiency (HHV)	%	88.07	88.61	0.01
		VWO		
SH outlet steam flow	kg/h	354636	352284	-0.66
SH outlet steam flow	kg/s	98.51	97.86	-0.66
Net power	MW	126.47	126.35	-0.1
Heat input (HHV)	MJ/s	330	330	0
boiler efficiency (HHV)	%	88.1	88.61	0.58
		100% TMCR		
SH outlet steam flow	kg/h	343656	340134	-1.02
SH outlet steam flow	kg/s	95.46	94.48	-1.02
Net power	MW	122.51	123.72	0.99
Heat input (HHV)	MJ/s	320	320	0
boiler efficiency (HHV)	%	88.16	86.79	-1.56

The result of validation between GeatCycle application and data of design operating condition from the boiler maker in case of boiler maximum continuous rate (BMCR), case of valve wide open (VWO) and turbine maximum continuous rate (TMCR), the error from the validation are not more than 1.56% which consists of steam flow (kg/s), net power (MW) and boiler efficiency as shown in Figure 4-8.

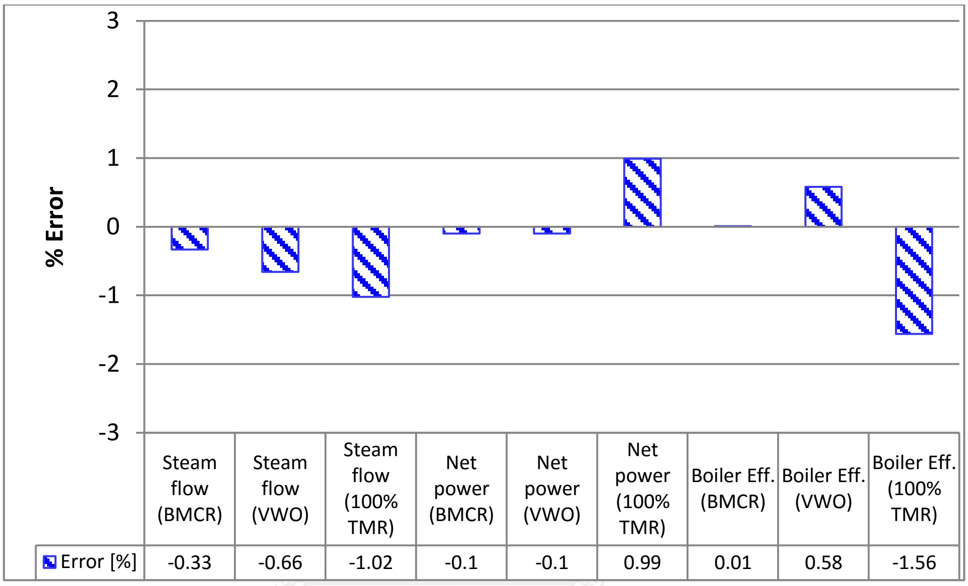

Figure 4- 8 The comparison of error of each case with the GateCycle

4.5 The modeling of heat recovery from recycled flue gas

In this case, the system of oxy-combustion power plant has an added heat exchanger to transfer heat between recycled flue gases back into the boiler and a feed water heater system. This case utilizes waste heat in the recycle flue gas to heat up the water feed inlet to the boiler process.

The addition of this heat exchanger is reflected in the boiler efficiency, power generation and turbine efficiency evaluation. The conditions of oxy-combustion with the coal-fired power plant and recycle flue gas (RFG) ratio at the optimal condition, and other variables are as install the heat exchanger before FWH1, FWH2, FWH3 and FWH4 respectively.

The process flow sheet from the GateCycle of the adding heat exchanger into the oxy-fuel combustion of coal-fired power plant as Figure 4-9

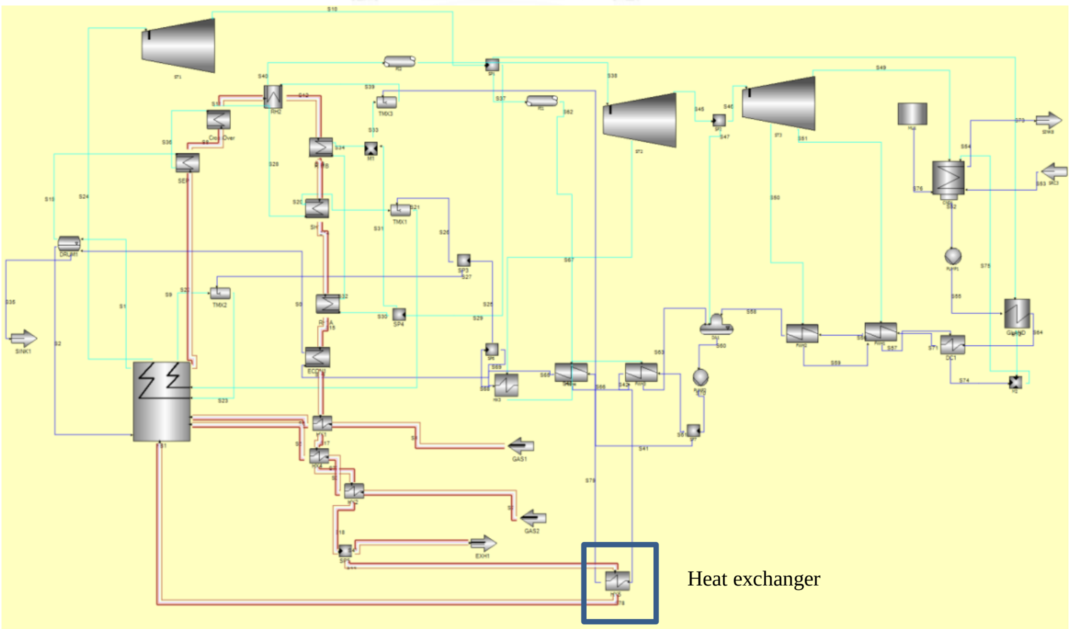

Figure 4- 9 The oxy-fuel combustion of coal-fired power plant with heat exchanger before FWH4

CHAPTER V

Result and Discussion

The following cases are studied the conditions evaluate the comparison of the performance evaluation of the oxy-fuel combustion of the power plant listed below:

Case I: The comparison of oxy-fuel combustion and air-combustion of coal-fired power plant

Case II: Effect of operating parameter of oxy-fuel combustion of coal-fired power plant

- Effect of recycled flue gas
- Effect of oxygen concentration

Case III: The heat recovery of recycle flue gas

5.1 The comparison of oxy-fuel combustion and air-combustion of coal-fired power plant

The aim of this section is preliminary investigate the oxy-fuel combustion of coal-fired power plant which compare to the air-combustion. The condition of oxy-fuel combustion is at 0.7 recycle flue gas ratio and oxygen purity 0.95% mass. The coal-fired power plant is operated at boiler maximum capacity rate (BMCR). The result is shown in Table 5-1. The result shows that gross power generation of oxy-fuel combustion increases from 131.8MW to 135MW and the turbine efficiency increases from 44.14% to 46.43%. The flue gas energy loss decreases from 27.5MJ/s to 13.8 MJ/s.

Table 5- 1 The result of oxy-fuel combustion compared to the air-combustion

		Unit	Case Air-fired	Case Oxy-95%
Gross Power		MW	131.8	135.11
Power Consumption	Auxiliary	MW	5.46	5.91
	ASU	MW	-	16.87
	CPU	MW	-	9.66
Net power		MW	126.35	102.67
Net Heat rate		BTU/kWh	8064.57	9670.83
Boiler efficiency		%	88.61%	86.35%
Net efficiency		%	37.49%	30.47%
Turbine Thermal Efficiency		%	44.14%	46.43%
Turbine Efficiency (Net)		%	42.31%	35.28%
Adiabatic flame temperature		deg C	1675.85	1716.49
Enthalpy		kJ/kg	163.02	307.76
Flows		kg/sec	16867.00%	4491.00%
Argon, AR		fraction	1.00%	3.00%
Carbon Dioxide, CO2		fraction	13.00%	57.00%
Nitrogen, N2		fraction	73.00%	2.00%
Oxygen, O2		fraction	0.04	0.05
Water, H2O		fraction	0.09	0.33

5.2 Effect of operating parameter of oxy-fuel combustion of coal-fired power plant

The operating parameters of the oxy-fuel combustion of coal-fired power plant affect the performance of power plant. The operating parameter that is investigated consists of the recycled flue gas ratio and oxygen concentration. The oxygen purity in the oxidizer is varied from 95% mass fraction of O_2 (Argon 4% mass fraction and 1% N_2 mass fraction) to 99% mass fraction of O_2 (Argon 0.08% mass fraction and 0.02% N_2 mass fraction) by increasing step is 0.01. The recycle flue gas ratio is varied from 0.5 to 0.8. The results are evaluated using the boiler efficiency, power generation and turbine efficiency. The oxy-fuel combustion of oxy-fuel combustion is based on the boiler maximum continuous rate (BMCR) condition which heat input into the boiler at same level of air-combustion at 337 MJ/s. The auxiliary load of the components of the air separator unit (ASU) and CO_2 purification unit (CPU) is 16.87 kW and 9.66 kW respectively. The limit of the condition is in below details.

- 95% of O_2 purity (Argon 4% mass fraction and 1% N_2 mass fraction)
- Excess oxygen is not more than 5%
- 337 MJ/s Heat input into the boiler
- 580 temperature at inlet high pressure turbine
- 570 temperature at inlet intermediate pressure turbine
- Stack temperature is not lower than acid dew point 170°C
- Water feed inlet into the water must not be the supercritical state

5.1.1 Effect of recycled flue gas

The aim of this section is to analyze the recycle flue gas ratio of the oxy-fuel combustion with the existing coal-fired power plant. The condition of the oxy-fuel system is maintained the concentration of oxygen purity at the inlet boiler 0.95% mass, the condition of the power plant is operated at the boiler maximum continuous rate condition. The performance in term of the boiler efficiency, power generation, turbine efficiency of the power plant and the flue gas condition in term of flue gas temperature, composition in the flue gas and energy loss in the flue gas are investigated. The recycle flue gas ratio is varied 0.50 to 0.80 because the limit of the operating condition and the turbine material. The optimum condition of recycled flue gas is investigated by the suitable boiler efficiency and power generation of the coal-fired power plant.

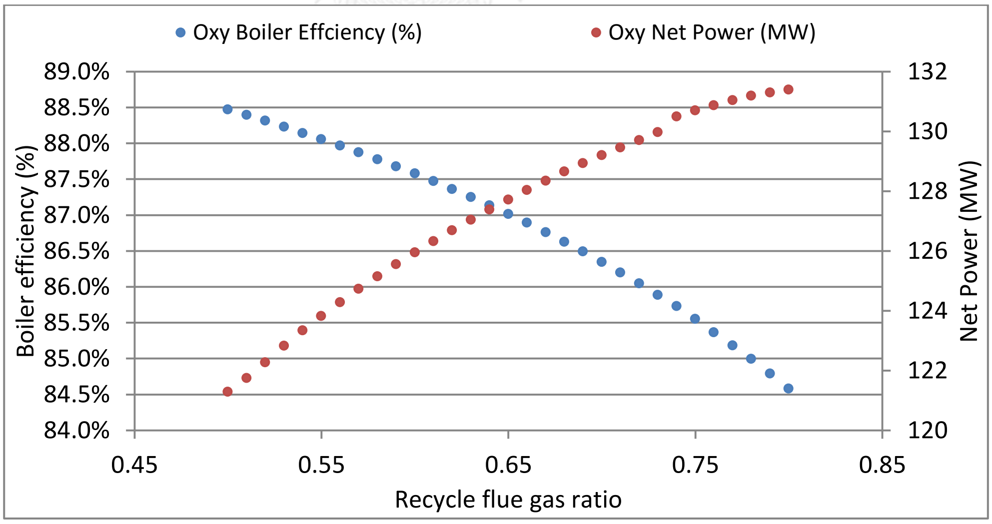

Figure 5- 1 The optimized of the recycle flue gas ratio

The result of the recycle flue gas ratio that effect to the boiler efficiency (%) and the net power (MW) is optimized at the recycle flue gas ratio 0.64 as shown in the Figure 5-1 because the boiler efficiency and the net power is crossed. At 0.64 RFG ratios the boiler efficiency is compared to air-fired condition decreases from 88.61%

to 87.13% and the net power increases from 126.35 MW to 127.39 MW. The higher recycle flue gas, the lower boiler efficiency and the higher net power. If recycle flue gas ratio is lower than 0.5 RFG ratio, the pressure of feed inlet to the water wall is at 230 bar which higher than the critical pressure at 220.55 bar. The limit of the operating condition effect to the pressure of the water from drum to feed water inlet to the boiler that the water inlet is changed the state to the supercritical state. If recycle flue gas ratio is higher than 0.8 RFG ratios, the temperature inlet intermediate turbine is higher than 565 °C that is the limit of the inlet temperature and effect to the material of steam turbine. Due to the modeling is operated at steady state condition then the desuperheat that used to control temperature of steam in the system is not operated. Therefore, the modeling need to find the optimal condition that can be operated and did not effect to the material of the steam turbine and heat exchanger in the power plant. The adiabatic flame temperature and the temperature inlet IP turbine are limited.

The result shown that the adiabatic flame temperature of air-combustion is 1675 °C, the RFG ratio is higher 0.71 to achieve the adiabatic flame temperature that is not effect to the material of steam turbine. Then the higher RFG ratio is effect to the combustion in the furnace, the lower adiabatic flame temperature. The limit of temperature inlet IP turbine that effect to the material and operating condition is at 565 °C, the RFG ratio should lower than 0.75 fractions as shown in the Figure 5-2.

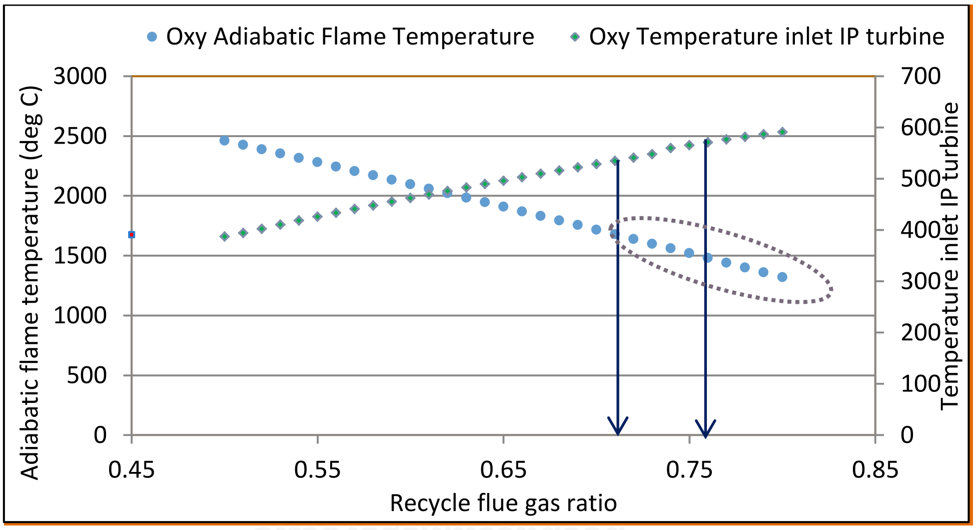

Figure 5- 2 The adiabatic flame temperature and temperature inlet turbine at condition of recycle flue gas ratio

The performance result of varying the recycled flue gas ratio between 0.6 to 0.8 RFG is shown in Figure 5-3 the boiler efficiency decreases from 87.58% to 84.58% respectively. The net power that include auxiliary load of air separator unit and CO2 purification unit increases from 125.95 MW to 131.40 MW. The turbine efficiency increases from 42.67% to 46.10% at the 0.6 to 0.8 RFG ratio. The result mean that the higher recycled flue gas ratio, the lower boiler efficiency and the higher of the net power that include auxiliary load of ASU and CPU.

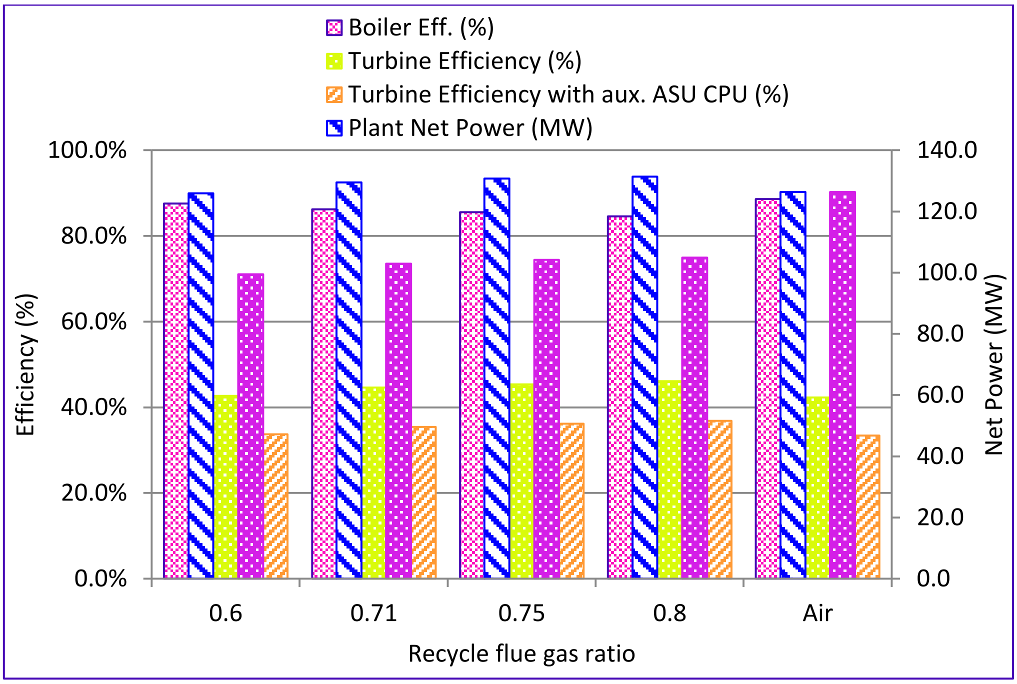

Figure 5- 3 The performance of the power plant at condition of recycle flue gas ratio

The flue gas condition is investigated. The aim of the oxy-fuel condition is increased the concentration of carbon dioxide and moisture in the flue gas that is easy to the separation in the carbon dioxide purification unit. The result in the Figure 5-4 is shown that the composition of flue gas in mass fraction, the higher recycle flue gas ratio the carbon dioxide and water composition are higher. For the nitrogen composition is not significant change when RFG is changed. The composition of the carbon dioxide and water composition increase from 0.13 to 0.57 and 0.09 to 0.34 when compared to air-combustion. The nitrogen composition in the flue gas decreases from 0.72 to 0.02 mass fractions.

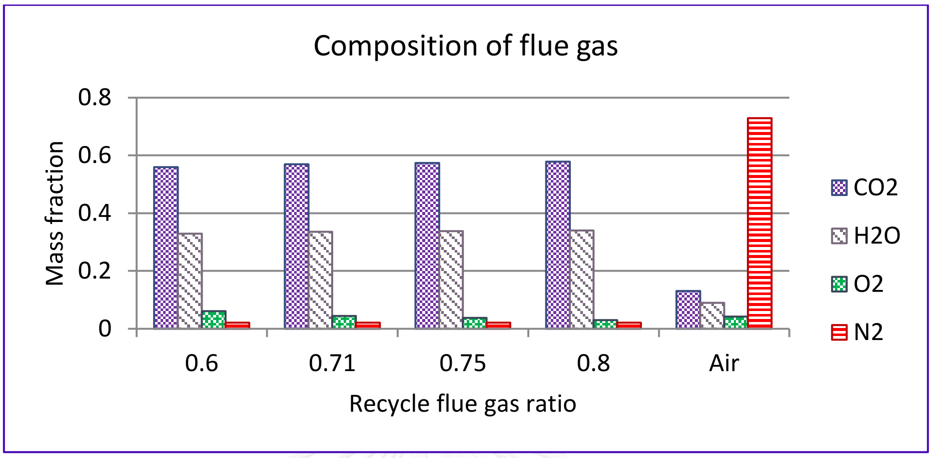

Figure 5- 4 The composition of flue gas at condition of recycle flue gas ratio

The condition of flue gas in the Figure 5-5 is shown that the higher of RFG ratio, the higher energy loss of flue gas due to the boiler efficiency decreases from 27.5 to 14.01 MJ/s when compared to air-combustion.

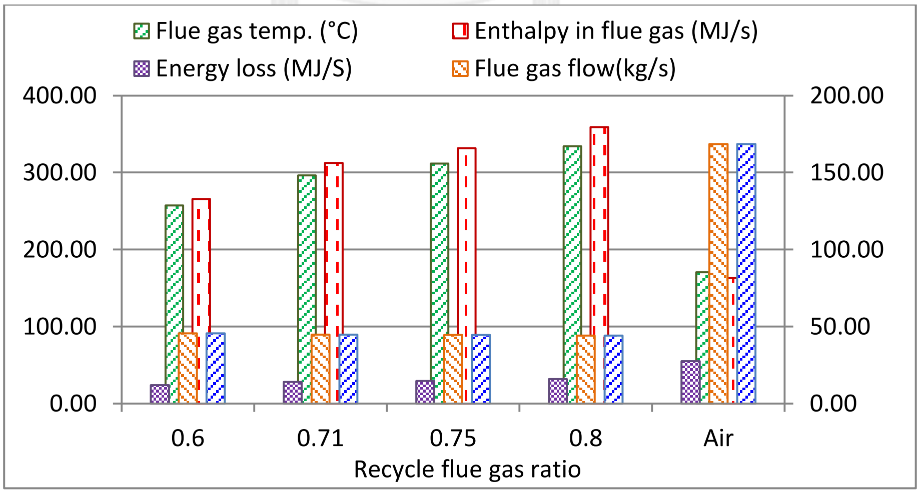

Figure 5- 5 The condition of flue gas at the recycle flue gas ratio

The flue gas temperature is increased and the temperature of oxygen inlet to the boiler is increased from 226 °C to 338 °C at 0.71 RFG ratios as shown in figure 5-6. The gas feed (oxygen) inlet to the boiler decreases 80% when compared to the air-combustion. This mean that the RFG is substituted the volume flow of the oxygen in the boiler.

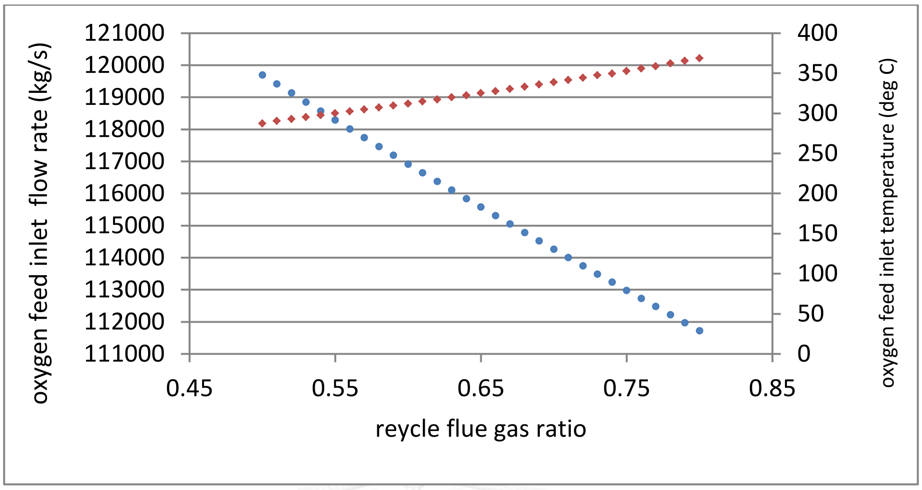

Figure 5- 6 The condition of oxygen inlet flow rate and temperature inlet boiler at the recycle flue gas ratio

The specific heat capacity is the heat that effect to increase temperature 1K/mass as shown in Figure 7- 8. The enthalpy of flue gas is higher due to the temperature is higher and the composition of carbon dioxide increases and C_P of CO_2 is higher than N_2 at the temperature more than 276.85°C.

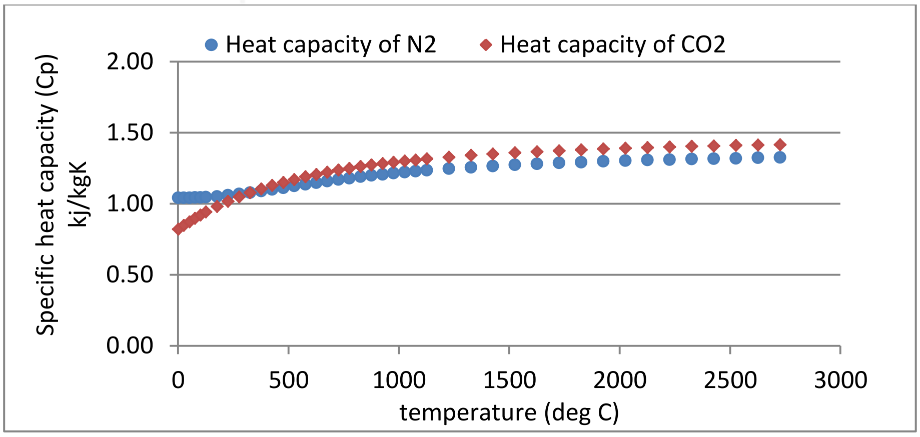

Figure 5- 7 The specific heat capacity (C_p) of N_2 and CO_2

Conclusions

As mentioned, the results show that the oxy-fuel combustion with the existing coal-fired power plant by varying the RFG ratio can improve the Plant Net Power but decrease Boiler efficiency. The adiabatic temperature and temperature inlet IP turbine is not higher than 1675 °C and 565 °C respectively then RFG ratio is 0.71 to 0.75. The higher RFG ratio, the CO_2, H_2O in the flue gas is higher but N_2 is not significant change. The CO_2, H_2O in the flue gas is higher but N_2 is decreased in significant which compared to conventional combustion case.

5.1.2 The effect of the oxygen concentration

The aim of this section is to analyze the oxygen concentration of the oxy-fuel combustion of coal-fired power plant. The condition of the oxy-fuel system is maintained the recycle flue gas ratio at 0.71, the condition of the power plant is operated at the boiler maximum continuous rate condition. The performance in term of the boiler efficiency, power generation, turbine efficiency of the power plant is investigated. The oxygen concentration is varied 0.95 to 0.99 because typically of oxygen concentration is produced as high as concentration in the air separator unit. The auxiliary load of the oxygen production by air separator unit is not taking into account due to lack of power consumption in air separator unit data. The optimum condition of oxygen concentration is investigated by the suitable boiler efficiency and power generation of the coal-fired power plant.

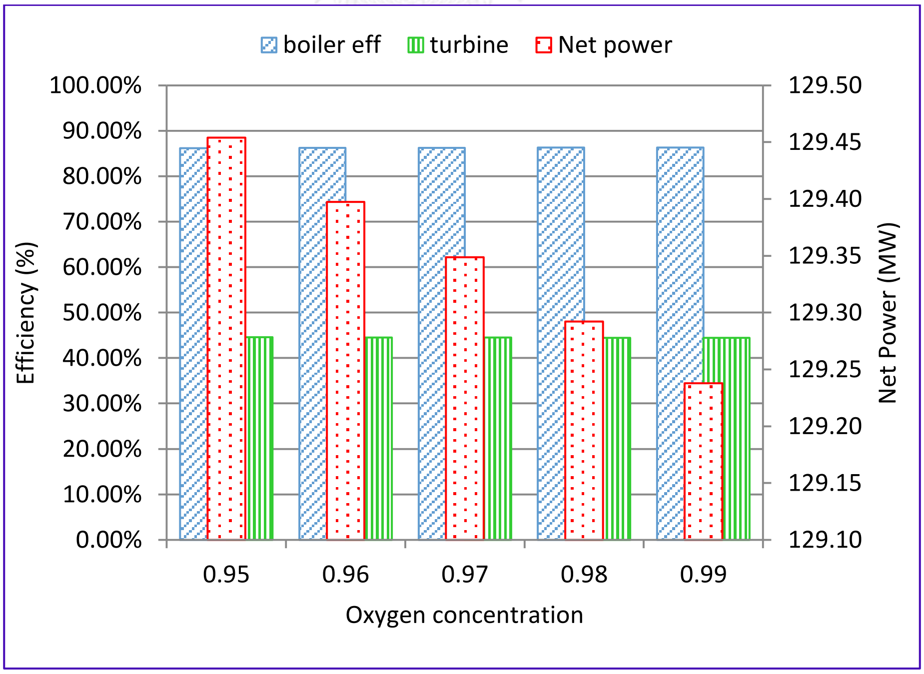

Figure 5- 8 The performance of the power plant at condition of oxygen concentration

The result of boiler efficiency, power generation and turbine efficiency is shown in Figure 5-8. The result of the purity of oxygen inlet that effect to the boiler efficiency (%) and the net power (MW) which improve the boiler efficiency but the power generation and the turbine efficiency is decreased. The boiler efficiency of 0.95%, 0.96%, 0.97%, 0.98% and 0.99% mass oxygen are 86.20%, 86.23%, 86.26%, 86.29% and 86.32% respectively. The net power of plant at 0.95% to 0.99% oxygen decreases from 129.45 to 129.24MW by decreasing 0.05MW per oxygen concentration and turbine efficiency is decreased from 44.56% to 44.43% by changing oxygen concentration from 0.95% to 0.99%.

For the adiabatic flame temperature is increased from the higher oxygen concentration which are 1677.7°C, 1682.5°C, 1687.1°C, 1691.8°C and 1696.3°C from changing oxygen concentration 0.95% to 0.99% as shown in Figure 5-9.

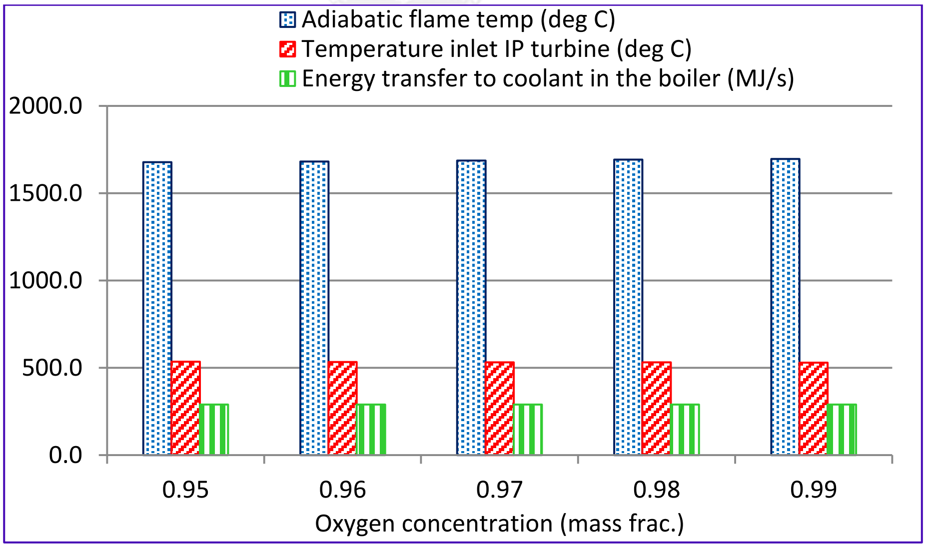

Figure 5- 9 The adiabatic flame temperature, the inlet temperature of IP turbine and the energy transfer to coolant in the boiler at oxygen concentration.

The higher adiabatic flame temperature because the higher oxygen concentration effect to the concentration of recycle flue gas which mainly inert gas in the boiler is decreased. The energy transfer in the boiler which consists of duty at superheater1, reheater1 and water wall is increased as shown in Figure 5-10.

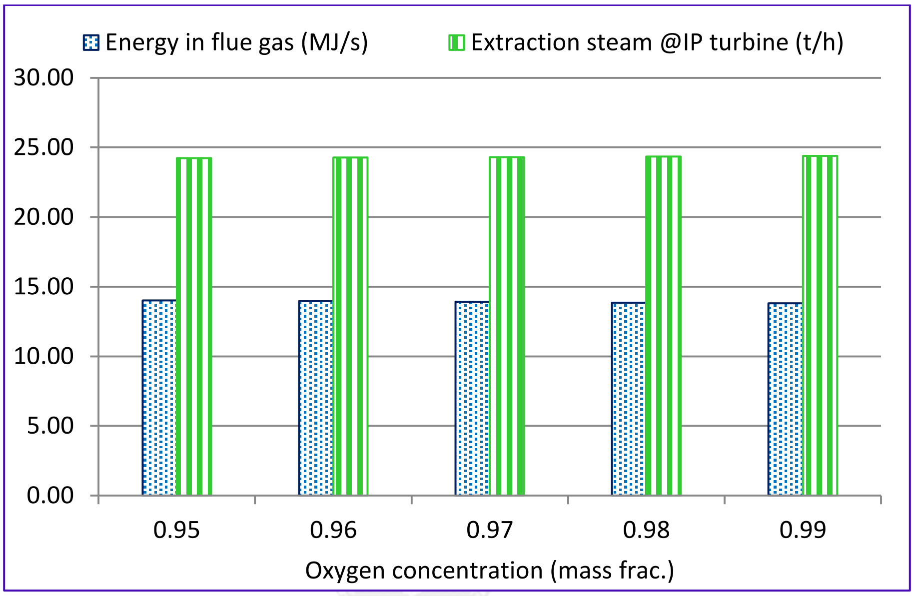

Figure 5- 10 The extraction steam at IP turbine and energy

in the flue gas at oxygen concentration.

The boiler efficiency is increased because the heat absorb at boiler is higher and heat input to the boiler is maintained at 337MJ/s according to boiler maximum continuous rate. The energy transfer to the boiler is increased from 290.5 to 290.9 as oxygen concentration changing. The result of energy in the flue gas transfer in the back path section which consists of reheater2, 1B, 1A, superheater2 and economizer is decreased therefore the temperature of hot reheat from reheater2 is dropped. The inlet temperature of intermediate pressure turbine is decreased then the temperature of feed water heater inlet to the boiler decreases and requires more extraction from steam turbine to heat up the water inlet to the boiler. The steam turbine losses steam to generate power. The energy in the flue gas loss is decreased as shown in Figure 5-10 due to the higher concentration of oxygen can be reduce the concentration recycle flue gas in the boiler. For the composition in the flue gas, the higher oxygen concentration the CO_2 and H_2O concentration is higher from 56.96% to 58.74% mass CO_2 and 33.53% to 34.58% mass H_2O and the concentration of nitrogen is decreased from 2.11% to 1.55% mass N_2 as shown in Figure 5-11.

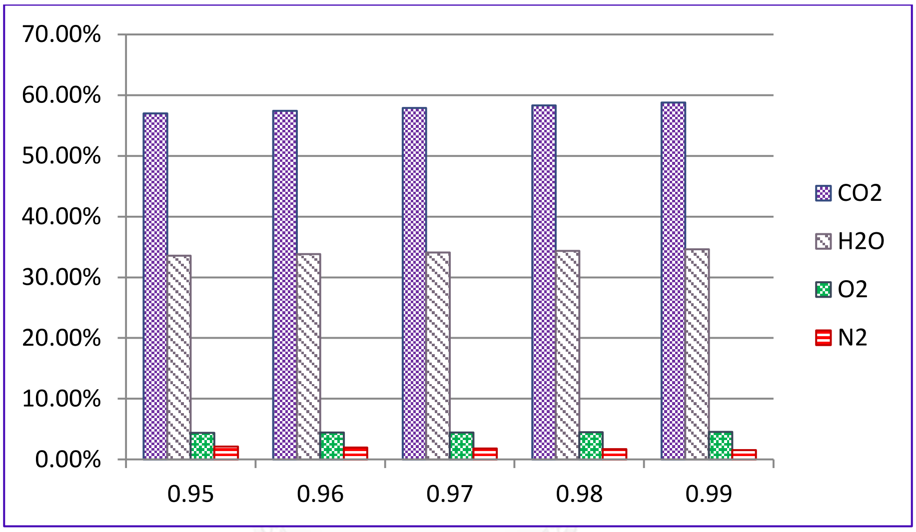

Figure 5- 11 The composition of gases in the flue gas at oxygen concentration.

Conclusions

As mentioned, the results show that the oxy-fuel combustion of coal-fired power plant by varying the concentration of oxygen can improve the boiler efficiency but decrease the power generation. The higher concentration of oxygen, the CO_2, H_2O in the flue gas is higher and N_2 is decreased. Although the higher concentration of oxygen can be improved the boiler efficiency but typically the auxiliary load of air separator unit is increased by the purity of oxygen production. Generally, the oxygen is effect mainly on the flame stability and heat transfer characteristics in the oxy-fuel combustion and can be effect to the lower content of carbon in the ash.

5.1.3 Heat recovery of recycled flue gas

The aim of this section is to analyze the heat recovery from recycle flue gas of the oxy-fuel combustion of coal-fired power plant. The condition of the oxy-fuel system is maintained the recycle flue gas ratio at 0.71 and oxygen concentration at 0.95%mass, the condition of the power plant is operated at the boiler maximum continuous rate condition. The performance in term of the boiler efficiency, power generation, turbine efficiency of the power plant is investigated. The heat of recycle flue gas is recovered by adding heat exchanger to transfer heat between recycle flue gas and boiler feed water at the position before FWH1, FWH2, FWH3 and FWH4. The performance of feed water heater in term of terminal temperature difference is investigated.

The results of heat recovery from recycle flue gas by adding heat exchanger that effect to the boiler efficiency (%)the net power (MW) and turbine efficiency(%). The position of heat exchanger before FWH2 is the optimal position due to the highest power generation at 129.06MW as shown in Figure 5-12.

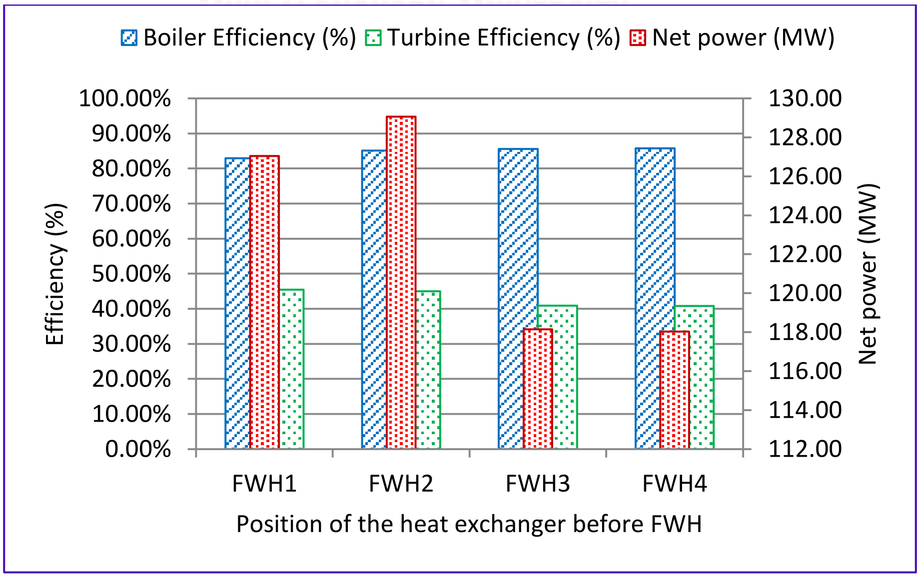

Figure 5- 12 The performance of the power plant at condition of the position of FWH

The boiler efficiency and turbine efficiency are higher when the position of FWH is near the boiler due to the water that feed through the feed water heater is heated up before send to the boiler and the higher energy transfer in the coolant of the boiler. Therefore the total duty at the radiant superheater, radiant reheater and furnace wall as Figure 5-13 are 181.74, 187.63, 191.05 and 191.43 MJ/s at FWH1 to FWH4 respectively.

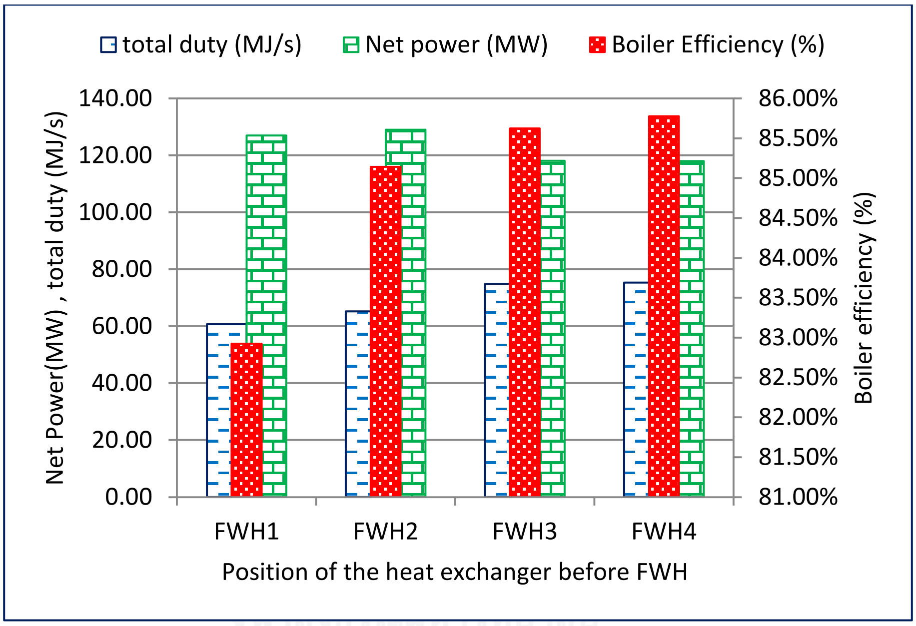

Figure 5- 13 The performance and the total duty of the power plant at condition of the position of FWH

The gross power production from HP steam turbine of heat exchanger that place before FWH1 and FWH2 are 37.29 and 37.57 MW. The gross power production from IP and LP steam turbine is higher when the position of heat exchanger is near the boiler (before FWH3 and FWH4), the steam extraction flow from IP and LP steam turbine is higher also. Therefore the power production and steam extraction from turbine stage is tradeoff. The gross powers from HP steam turbine at the FWH3 to FWH4 are 18.86 and 18.77 MW respectively. The gross power from HP steam turbine loss approximately 19 MW due to the temperature of main stream at outlet boiler decreases from 568 °C to 507 °C and 504°C when integrate the heat exchanger before FWH3 and FWH4 respectively.

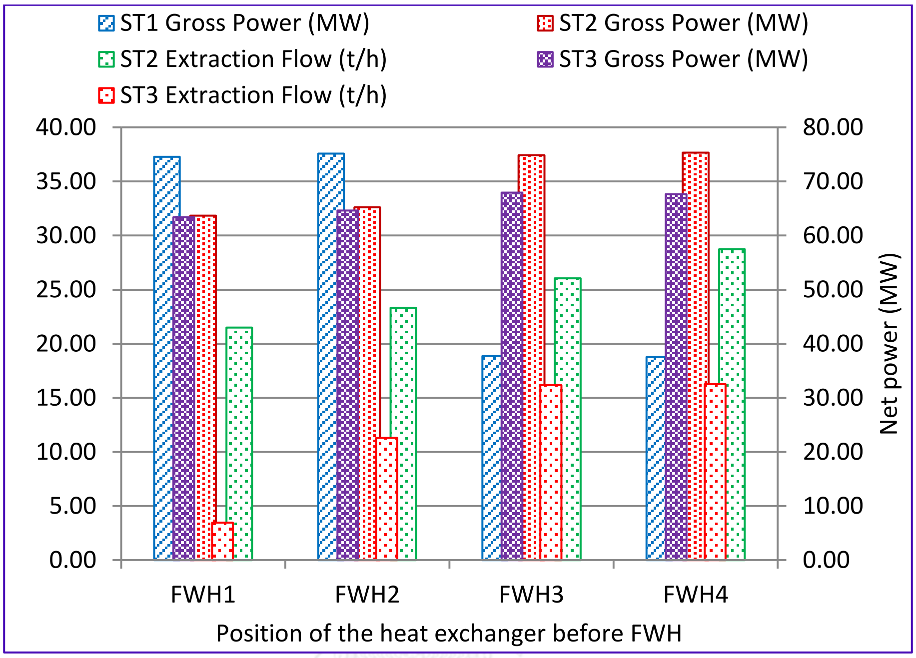

Figure 5- 14 Gross power generation (MW) and the steam extraction flow (t/h)

Moreover, the main stream flow is send to HP turbine for power generation decreases from 564 ton/hour to 419 ton/hour and 422 ton/hour respectively. Furthermore, the performance of the FWH can be monitored by using the terminal temperature difference (TTD) that is the difference temperature between steam inlet and feed water outlet temperature. Typically the TTD for FWH should not more than 5 °C due to effect to cracking or leak on the tube in the FWH.

CHAPTER VI
Conclusion and Recommendation

6.1 Conclusions

The purpose of this study is the simulation and optimal parameter analysis of the oxy-fuel combustion of coal-fired power plant. The simulations are validated with design operation plant data and are good acceptable simulation. The operating condition of oxy-fuel combustion coal-fired power plant consists of the effects of recycle flue gas and oxygen concentration in term of boiler efficiency, power production, and adiabatic flame temperature, temperature of turbine limit and flue gas condition. The higher recycle flue gas ratio, the lower boiler efficiency. For the oxygen concentration affect to the combustion in the furnace directly. Therefore, the results can identify the optimal operating condition for the system and is used to enhance performance of the coal-fired power plant.

In addition, The heat recover in the oxy-fuel combustion of the coal-fired power plant by adding the heat exchanger to transfer heat between recycled flue gases back into the boiler and a feed water heater. The waste heat loss is utilized by return heat to the power plant. The position of heat exchanger before deaerator is the optimal position because the higher heat transfer in the feed water heater and terminal temperature difference is not effect to the performance of feed water heater. This case has to analyze in the detail of the various variable because the condition to enhance the performance of the power plant. The heat recovery effects to the boiler efficiency and steam cycle efficiency.

6.2 Recommendations

This research is a preliminary study of the oxy-fuel combustion with coal fired power plant which is steady state simulation and thermodynamic calculation. Therefore the performance and operating condition of the simulation is only the elementary calculation because of various assumptions. Then, the future works should be study in the detail and design complex system that close to the actual operating condition which should use the actual condition by importing data via macro application in the dynamic model. Furthermore, this performance of the power plant should be investigated by the exergy analysis.

APPENDIX

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