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Biomass based oxyfuel combustion in CHP power plant with opportunity of oxygen storage system for carbon capture and storage

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Abstract:

Carbon dioxide (CO_2) emission from coal-based power plants is one of the major environmental concerns since coal will remain as a dominant source of energy for the next few decades. Therefore, the CO_2 emission requires to be decreased and move towards renewable energy sources to meet the environmental and sustainability targets. However, it will not be able to meet the worldwide energy demand because of the limited commercialization of renewable energy sources. As coal is the most leading energy source, it is necessary to divert a considerable phase of research work in CO_2 capture and utilization for coal-based power plants to achieve the global environmental targets.

In this thesis, overall features for power plant process modeling and optimization with the provision of carbon capture, oxyfuel combustion and district heating have been analyzed. The process model was designed and simulated by Prosim software changing the key parameters of coal and biomass blending and various district heating loads. The simulation results for the proposed power plant explain the effect of biomass co-firing on net efficiency (heat and power) and power consumption for Air Separation Unit (ASU), oxygen storage linked with grid electricity price and analysis of power to heat ratio. From the analysis, increased net efficiency was originated with adding more biomass with coal. This research work also focuses the general economic evaluation for oxygen storage in relation to electricity and district heating price with optimization software GAMS.

Most of the research works in this field are concentrating towards carbon capture and storage only. The approach behind the thesis focuses to incorporate different variables for a proposed system along with effect of selected key variables for the process optimization.

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List of abbreviations and notations

ASU	Air Separation Unit
CCS	Carbon Capture and Storage
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
CPU	Carbon Compression and Purification Unit
CO	Carbon monoxide
CO_2	Carbon dioxide
DH	District Heating
ETS	Emission Trending Scheme
EU	European Union
FG	Flue gas
GAMS	General Algebraic Modeling System
H_2	Hydrogen
H_2O	Water
HP	High pressure
HPC	High pressure column
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate pressure
IPCC	The Intergovernmental Panel on Climate Change
kt	Kiloton
kWh	Kilowatt Hours
LHV	Lower Heating Value
LP	Low pressure
LPC	Low pressure column
CNG	Compressed natural gas
Mt	Million tons
MW	Megawatt
MWh	Megawatt Hours
N_2	Nitrogen

NO_X	Nitrogen Oxide
O_2	Oxygen
PF	Pulverized Coal
RFG	Recycled Flue Gas
SO_X	Oxides of Sulfur
USD	United States Dollar

$\dot{m}$	mass flow
p	pressure
P	power
s	second
T	temperature
th	thermal
e	electrical
€	euro

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1 Introduction

Sustainable energy production is now an immense concern for the world. The reserve of fossil fuels (oil, coal and natural gas) is depleting and renewable energy sources (solar, wind, biomass, ocean wave and geothermal, etc.) are getting precedence for power generation. However, fossil fuel will still be dominant (especially coal) over the 21st century. In contrast, power generation from fossil fuel is one of the major sources of greenhouse gases. Therefore, efficient usage of fossil fuel is a key question. The carbon capture and storage technology includes the approaches by which greenhouse gas like carbon dioxide (CO_2) is captured from flue gas, mechanically compressed and stored in the underground [1-2]. Oxyfuel combustion of coal is now a promising technique, where coal burns with pure oxygen (O_2) instead of air. In addition, biomass can be used with coal to reduce fuel cost and positive effect on environment [1,3].

Existing power plants are not equipped with the technologies of state of the art for carbon capture. Authorities focus on flue gas cleaning and carbon tax. Carbon tax and cost for scrubbing gas will increase in the future. On the other hand, oxyfuel combustion and carbon capture method will reduce CO_2 in the flue gas. This combustion method has been conducted in several demonstration projects for power generation plant since 2006 [1]. However, capture technology is still expensive. Opportunities of the biomass based oxyfuel combustion and carbon capture highly depend on precise results from the demonstration plants.

Energy production from conventional fossil fuel fired plants is the dominant contributor to greenhouse gas emission. It is a well-known fact that greenhouse gas emission can be reduced by the use of renewable energy sources. However, the commercialization of the renewable energy sources is limited due to its intermittent nature. Therefore, the role of the coal-fired power plants will remain dominant to meet the global energy demand. As a result, the research associated with the emission from the coal-fired power plants will be interesting field to pursue.

1.1 Background

In past and in foreseeable future, coal-based power plants will be the main sources of electricity to satisfy the global energy demand, because 100 % transition to renewable energy sources will be quite impossible within next few years. The current challenge is to maintain the energy mix of coal-based power plants in a carbon-constrained world by reducing the greenhouse gas emission from the utilization of coal as a source of energy. To reduce CO_2 emission from coal-based power plants, several technologies or ideas are adopted like efficiency improvement of power plants, oxyfuel combustion with flue gas recirculation, carbon capture and storage and co-firing of coal with biomass [1,6,7,8,9]. This kind of research and development with coal-based power plants is gaining interest among the big energy companies across the globe. Therefore, the present thesis work will address this challenge of energy industries to reduce CO_2 emission from coal-based power plants.

In International Outlook Report 2011 [4], coal has been projected as dominant fuel for electricity generation worldwide in future. Coal for electricity generation contributed 40% of total supply of electricity over the world in 2008. Unlike 2008, its share may decline to 37% in the projected year of 2035. Figure 1.1 illustrates a clear domination of coal in future energy sources for generating power.

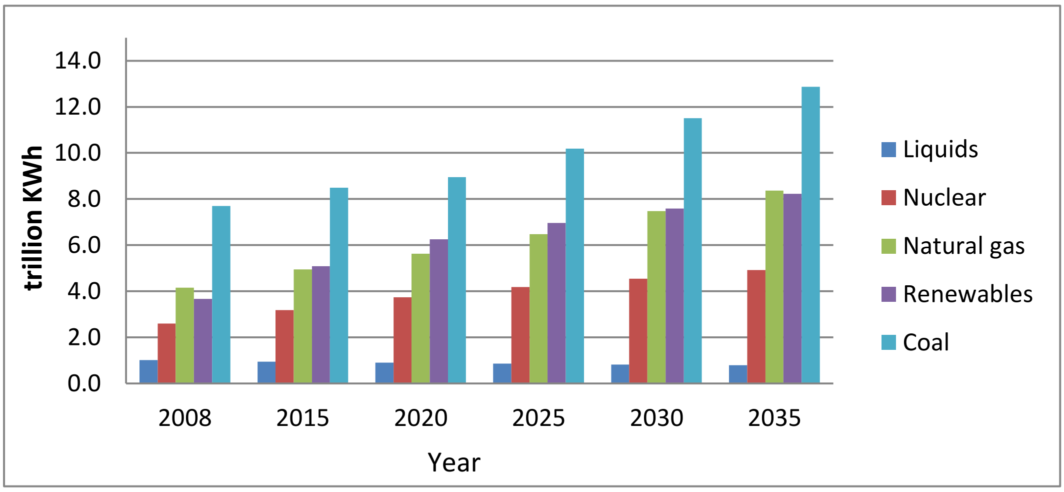

Figure 1.1: World net electricity generation by fuel, 2008-2035 [4].

Similarly, carbon dioxide (CO_2) emission from coal will be large part in the projection 2035. Interestingly, coal share in worldwide CO_2 emission indicates an inverse pattern. Emission from coal accounts for 43% in 2008 and 45% in 2035 (projected). Figure 1.2 shows that the most carbon intensive fossil fuel is still leading source of CO_2 emission, and no sign of changes will be observed until 2035 [4].

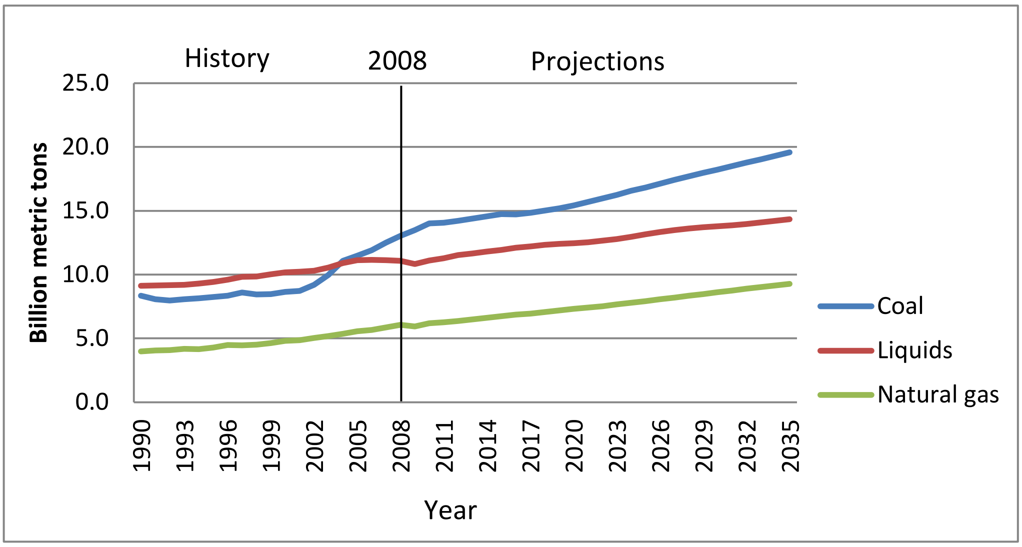

Figure 1.2: World energy-related CO_2 emission by fuel, 1990-2035 [4].

Due to the dominant characteristic of coal in electric power generation and CO_2 emission in future, economic and environmental measures are greatly required to control greenhouse gases with promising technologies. Carbon capture and

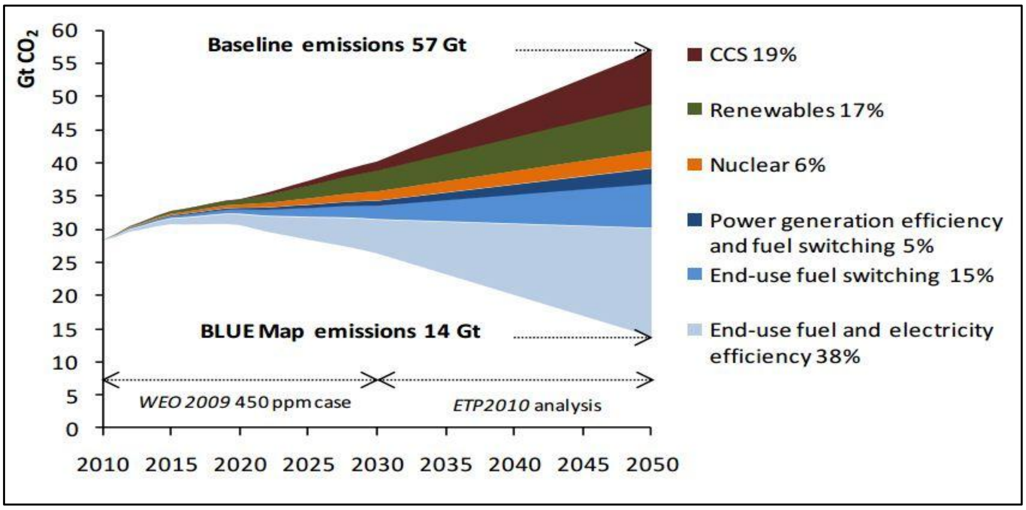

Figure 1.3: Key technologies for reducing CO_2 emissions [5].

storage (CCS) has vast potentiality to perform an important role in upcoming years. Figure 1.3 represents International Energy Agency (IEA) Projection 2050 to reduce CO_2 emission. CCS will have 19% capability as key technology for combat to declining CO_2 level as well as global temperature [5].

1.2 Research problem

The objective for most of the researches done in this field was the investigation and optimization of power plants with oxyfuel combustion and carbon capture only. In this work, a slightly different formulation is used: “The objective is to design a multi objective optimization routine of a co-firing (blend of coal and biomass) in combined heat and power (CHP) plant considering oxyfuel combustion with 70% Flue gas recirculation, traditional carbon capture with remaining 30 % flue gas, provision of oxygen storage linked with grid electricity price and district heating provision as variables”. This multi objective optimization results will provide a solid background to make this new concept of carbon capture linked with distinctive variables commercially feasible.

1.3 Aim of the work

The objective of the thesis focuses on development of optimization approaches using multi objective variables, that will provide a scientific background for the implementation of carbon capture and oxyfuel combustion concept in coal-based power plants with environmental and commercial justification. The most critical part of the optimization is the proper selection of the variables to make the results useful for industries. It is also interesting from academic point of view to analyze and optimize different types of variables related to carbon capture in fossil fuel power plants.

1.4 Scope of the work

The focus of the thesis is to design a co-fired CHP plant with carbon capture to address sustainability issues related with fossil fuel power plants. The methods adapted to this work aim to solve the CO_2 emission problems of coal-based power plants along with commercial justification. The tasks in this research work are formulated as follows:

(a) Selection of energy efficient Air Separation Unit (ASU)
(b) Investigation and validation for 70% recirculation of flue gas
(c) Optimization of oxyfuel combustion
(d) Incorporation of district heating system
(e) Provision for oxygen storage
(f) Linking the concept of oxygen storage with grid electricity price.

1.5 Challenges

In this thesis work, several distinctive variables are presented for the optimization routine. The biggest challenge in this work is the appropriate incorporation of all these different concepts or variables in simulation software Prosim 5.6 with accepted justification model prepared by General Algebraic Modeling Software (GAMS) to design a feasible solution. Moreover, there are several practical challenges for the implementation of the optimization results, as listed below:

(a) Co-firing ratio of coal and biomass
(b) Burner design for oxyfuel combustion along with flue gas recirculation
(c) High energy consumption of ASU
(d) Dynamics of district heating price in the energy market
(e) Fluctuation of electricity price in the grid and oxygen storage concept.

2 Carbon capture technologies and oxyfuel combustion

2.1 Types of capture technologies

Carbon capture technologies can be divided into three categories: post-combustion, pre-combustion and oxyfuel combustion [1,2,6,7,8]. These combustion methods have different advantages and disadvantages. Figure 2.1 demonstrates these three types of carbon capture methods in plant configuration.

Post-combustion technology refers to the approach of carbon scrubbing from flue gas of the conventional pulverized coal-fired power plants by chemical absorption with mono ethanol-amine (MEA) [1]. Regeneration of the chemical sorbent uses about 80% of total energy of the system thus losing efficiency. However, development and research are being conducted for better solvents and reduction of the energy use in regeneration. Retrofitting to the existing plant is possible due to its installation at downstream of the boiler and cleaning system of the flue gas [6].

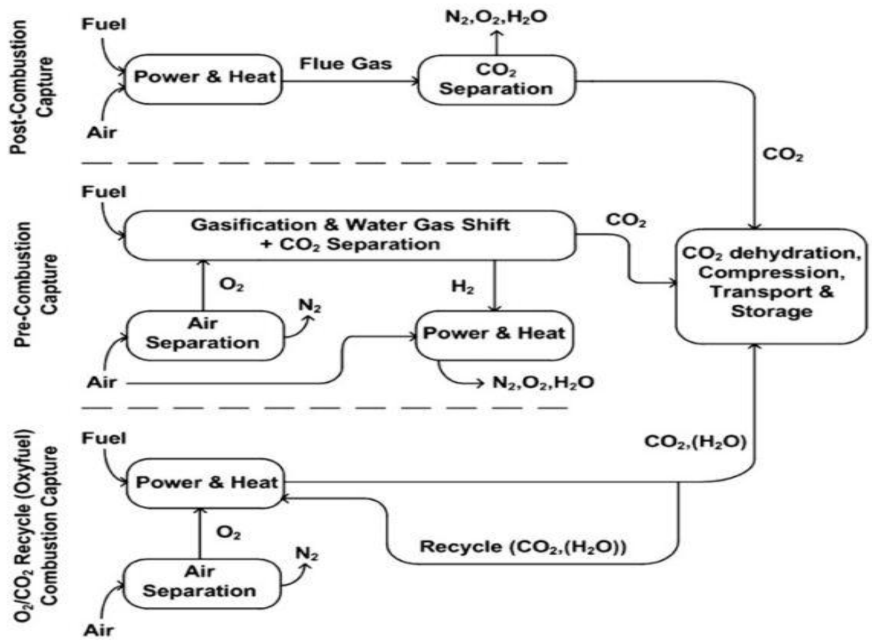

Figure 2.1: Three categories of carbon capture technologies [1].

Secondly, in **pre-combustion technique**, capturing of carbon is executed before combustion through gasification of coal. Coal is gasified to produce syngas containing CO_2, CO and H_2. Furthermore, water-gas shift reaction generates CO_2. H_2 is combusted in gas turbine. This combustion technique is combined with Integrated Gasification Combined Cycle (IGCC), where heat recovery steam generator and steam turbine are built-in [6]. Several experiments have been conducted for technical and economic calculations that demonstrate better plant efficiency. In contrast, plant construction requires high capital cost. There are few IGCC plants, but none of them include carbon capture and storage (CCS) systems [1].

Finally, **oxyfuel combustion technology** is being considered as a promising technique for carbon capture in conventional coal-based power plants [1,3,9,10]. This combustion approach uses pure O_2 rather than air. It results in a high portion of CO_2 in flue gas and water vapor. When the water vapor is separated, CO_2 becomes available for elimination. Moreover, some fractions of flue gas recycles for reducing the combustion temperature as pure O_2 causes high temperature in the combustion chamber [11].

This oxyfuel combustion method has several features those are significant for power plants. It does not include chemical process. Furthermore, nitrogen-free flue gas makes a difference. While separating O_2 from air, nitrogen (N_2) emits to atmosphere. As a result, no N_2 originated greenhouse gases (NO_x) is found in the oxyfuel based conventional power plants. Besides, separation of N_2 has a direct effect on equipment size and heat losses thus saving capital cost. Conventional power plants use air for fuel combustion that leads high volume of N_2 in flue gas. In power generation, N_2 contained flue gas has no positive impact [1,11]. In addition, lower emission is achieved in using oxyfuel combustion technique. Regular conventional boiler technology can manage oxyfuel combustion methods. Retrofitting of oxyfuel technology in existing power plants is being considered nowadays.

2.2 Oxyfuel combustion

Reduction of the CO_2 got priority since 1990s especially in the power generation industry. Abraham had proposed the concept of oxyfuel combustion in 1982, that was considered for use in oil recovery [9]. Satisfied results from several pilot and demonstration projects will contribute in commercialization of oxyfuel technology in the coal-based power plant. Figure 2.2 displays different oxyfuel based projects over the world that shows the increasing number of plants around the year of 2010. Interestingly, no plant is still operated in full phase as commercial power generation [12].

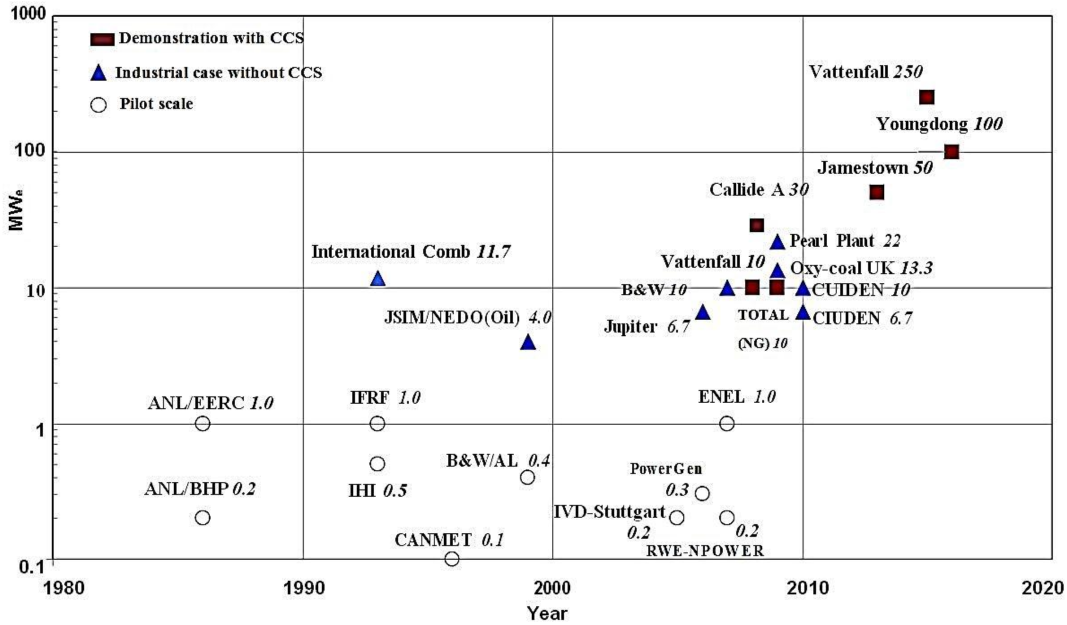

Figure 2.2: Progress of various oxyfuel pilot plants and demonstration projects [12].

The pilot project all over the world ranges 0.3-3.0 MW (thermal) and proposed demonstration projects varies from 30 MW (thermal) to 300 MW (electrical). More plants can be seen in Appendix A.

Figure 2.3 demonstrates the fundamental concept of oxyfuel combustion, where coal is burnt in O_2-CO_2 atmosphere (rather than O_2-N_2 atmosphere), then cleaned through gas cleaner and further sent for purification and compression. One portion of flue gas returns to the burner for providing CO_2 atmosphere with O_2 [8-9].

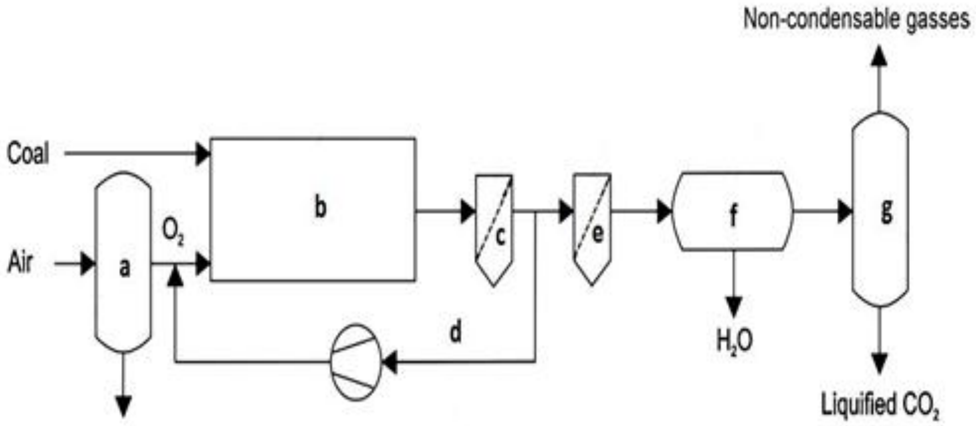

Figure 2.3: Simple block of oxyfuel combustion (a-ASU, b- furnace & boiler, c & e- gas cleaner, d- recycling flue gas, f- condenser, g- CO_2 compression and purification) [9].

2.2.1 Characteristics of oxyfuel combustion

Oxyfuel combustion is one of three separation methods that results in the reduction of greenhouse gases. Oxyfuel combustion method mostly emphasizes on the fossil fuel based power plants. However, this separation method triggers the decreasing efficiency of a power plant. The efficiency loss ranges 9-13%. However, it is likely to convert 7-11% by optimization of the plant. The nature of oxyfuel combustion differs from conventional air combustion in several ways. The furnace gas environment is a mixture of O_2 and CO_2 for oxyfuel combustion. Unlikely, air combustion takes place in O_2-N_2 environment. The characteristics include [9]:

2.2.1.1 Recycled flue gas (RFG) ratio

The main parameter for firing condition is flue gas ratio where a certain percentage of CO_2 adds to O_2 in burner and leads to change in temperature and heat transfer. Similarly, CO_2-H_2O retains higher specific heat capacity and different radiation and absorption characteristics. As a result, it is very important to select a range of flue gas ratio that will compensate the temperature characteristic of air combustion. Remarkably, many pilot and demonstration projects all over the world have been using the RFG ratio in the range of 0.6 - 0.85 [9,11].

2.2.1.2 Temperature of RFG

The temperature of flue gas has an impact on the combustion in relation to change the temperature of oxidant flow as pure oxygen (approximately 95%) mixes with RFG. Furthermore, the flue gas (CO_2-H_2O stream) mixed with oxygen affects the heat flux through boiler and boiler efficiency [11]. It has been studied that the temperature of the flue gas ranges over 100 °C to 400 °C considering different types of coal. For instance, the flue gas temperature for South African coal burnt ranges from 100 °C (RFG ratio 65.8%) to 400 °C (RFG ratio 68.6%). In contrast, flue gas shows 100 °C (RFG ratio 67.8%) and 400 °C (RFG ratio 71.7%) for Lusatian lignite. However, RFG temperature from the technically realistic purpose can be 200 °C – 400 °C. In that situation, the RFG ratio should be around 68-70% [9].

2.2.1.3 Oxygen concentration

While mixing with RFG in burner, high percentage of O_2 is required for better heat balance [9]. It should be considered that impact from CO_2 on coal ignition takes place if RFG ratio and burner aerodynamic are not properly optimized. Several studies show that high percentage of CO_2 environment causes retardation in coal ignition [13]. Moreover, less non-condensable impurities are found in CO_2 stream to capture while high percentage (more than 90%) of oxygen passes to the boiler. The optimal level of O_2 purity is 95%, which has been reported in several research works. However, argon with some traces of N_2 is also observed in oxygen production from ASU [11]. Better improvement in burnout has the possibility to happen in high concentration of O_2. But, sufficient O_2 is required to pass into the burner to ensure adequate ignition and flame stability [7].

2.2.1.4 Heat transfer

The characteristic of heat transfer in oxyfuel combustion is not similar as a conventional power plant. However, heat transfer is also related to the RFG ratio. A bit higher RFG ratio provides better heat transfer in the oxyfuel combustion [9]. To achieve better heat transfer, a reasonable RFG ratio should be adopted. In case of heat transfer, radiation is an important factor. CO_2, H_2O and different particulate matters (for instance, char, soot and fly ash particles) activate radiative heat transfer. Moreover, high concentration of CO_2 and H_2O mixture in boiler causes different emissive nature resulting manipulation of radiative heat transfer and absorption of heat in coal combustion [8,14]. The complex feature of heat transfer also considers the percentage of CO_2 and H_2O. As CO_2-H_2O mixture has high specific heat capacity than N_2, the mixture enables to retain more heat and contributes high heat transfer in convection section. However, lower amount of gas compared to air combustion and high heat transfer in radiative section results in decreased temperature in furnace exit gas. These features also act in decreasing heat transfer in convective section of boiler. Optimization is required in heat transfer in convective and radiative section of boiler to achieve efficient operation [1,9].

2.2.1.5 Combustion characteristics

From the findings of several research works, delayed ignition has been observed comparing to firing in air. However, situation changes when temperature increases. Interestingly, high percentage of O_2 indicates a higher rate of burnout of coal and biomass blends. Burnout of this blend in 79% CO_2-21% O_2 is less than burnout in 70% CO_2-30% O_2. Higher O_2 concentration has a vital effect in char combustion rate and ignition temperature [7-8]. Lower ignition temperature caused by high O_2 rate provides higher combustion time that turns in reaching higher burnout values. In addition, burnout value increases with more blending of biomass with coal. However, ignition temperature increases in O_2-CO_2 atmosphere compared to O_2-N_2 (air) atmosphere due to higher specific molar heat of CO_2 in comparison to N_2 [3,7]. It should be considered that biomass has lower calorific value and moisture content is higher than coal in firing. Due to these properties, declining rate of flame temperature may happen and radiative heat flux can be affected and thus reducing the oxidation rate. Furthermore, significant impact of ignition temperature should get priority in the high blending of biomass concentration [3].

2.2.1.6 Pollutant formation

NO_x Formation:

Formation of NO_x during combustion is a complex phenomenon. The factors causing the formation of NO_x includes, flame condition, O_2 concentration and flame temperature. Nitric oxide (NO) covers 95% of total NO_x. Decreased value of NO_x was found in several pilot-scale projects during oxyfuel combustion. The phenomenon happens due to the absence of N_2 gas in combustion atmosphere and decomposition of NO_x through the RFG (NO_x is contacted with hydrocarbon generated in reducing atmosphere) [15]. Besides, combustion mode and combustion temperature also result in reduction of NO_x. Technology used in the conventional coal power plants can be utilized in oxyfuel based coal power plant [8-9].

2.3 Circulating Fluidized Bed (CFB) boiler

CFB boiler is considered as a matured technology in the conventional power plants. The advantages of CFB boiler include better environmental performance and flexibility to use different types of fuels. The characteristics including better mixing of fuel, low air excess and good air staging enable CFB boiler for considering combustion purpose and reduction for NO_x emission. Furthermore, limestone used for Sulphur capture also performs well due to good mixing. Bed materials inside the CFB boiler demonstrate 90-98% of blending of fuel and bed materials. Sand and dolomite are used as common bed materials. Better combustion takes place with low air excess (lambda ranges over 1.1-1.2 for CFB plants) due to mixing and concentrated heat transfer. However, combustion temperature should be kept in the ranges of 650 °C-900 °C for preventing ash sintering in bed. CFB boiler is one of the best options for using the wide range of fuel as good mixing is achieved through the bed. Particle size of fuel should be less than 40 mm [16].

In addition, biomass blending with coal burns well in CFB. As a result, CFB boiler is one of the best choices for combustion coal and biomass together for the characteristic of fuel flexibility, longevity of combustion time and smooth combustion temperature [17]. However, more research works are required in some areas that have been proposed in many reviews includes [9]:

1. Combustion behaviors
2. Emission formation
3. Fouling, slagging and corrosion
4. heat transfer analysis
5. Validation of modeling and design tools.

Figure 2.4 presents diagram of a CFB boiler along with superheater, Economizer and air-preheater [18].

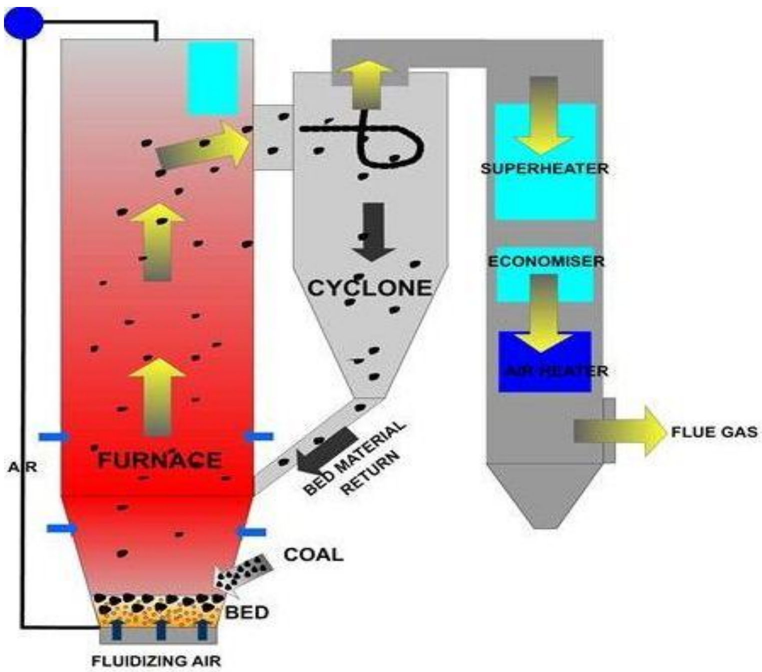

Figure 2.4: Diagram of a Circulating Fluidized Bed (CFB) boiler [18].

2.4 Biomass blending with CCS

As a source of renewable energy, biomass is used for balancing CO_2 emission. Using biomass as single fuel or blending with other fuels contributes in reducing CO_2 gases. While burning the biomass, combustion generated CO_2 gas is recycled to the atmosphere due to containing carbon in biomass in its life cycle. This energy source is accepted as carbon neutral. Co-firing of biomass with coal is getting priority in CHP plant incorporated with environmental friendly combustion and emission behaviour. Minor modification is required for co-firing coal with biomass. Moreover, using biomass in blending for combustion provides the scope to utilize biomass residue instead of land filling [3,17]. Maximum 10% of biomass blending is recommended due to particle sized constraints [19]. Biomass portion approximately 5% in co-firing does not cause any remarkable problem. On the other hand, high biomass percentage in co-firing (approximately 30%) may create problems in combustor like slagging and fouling [20].

In case of CCS strategies, the carbon neutral biomass can be easily adopted with co-firing. Combination of biomass with coal will contribute in removal of CO_2 emission. In addition, higher efficiency and lower cost are achievable in co-firing [19]. As there are no 100% efficient technologies available for CO_2 capture from flue gas, biomass usage in co-firing can compensate the losses and enable oxyfuel based CCS as net zero carbon emission [2].

2.5 District heating (DH) system in CHP plant

The combined heat and power concept mainly considers the simultaneous usage of heat and power from a source of fuel. Both types of demand for electricity and heat for residential area, city and industrial level are met up from a single CHP plant, where CHP is focused as a source of heat as a by-product with generation of electricity [21]. The CHP technology is considered as a favorable system where large portion of supplied fuel (70-95%) is used for both electricity and heat generation. In this system, the share of electricity generation is 20-50% considering the fuel and available technologies. In contrast, only 35-55% of fuel is driven for generation of electricity and rest of the fuel ends as useless product [16]. More than 100 million people over the EU and CEE countries get DH facilities. Moreover, DH system is considered as a significant product for CHP plant, especially in Western Europe. For instance, 75% DH supply is generated from CHP plant in Finland. Figure 2.5 demonstrates the several countries, like Denmark, Finland, Russia, Latvia and the Netherlands have got success in CHP features, where the expansion of CHP usage was achieved for 30-50% of total power generation [21].

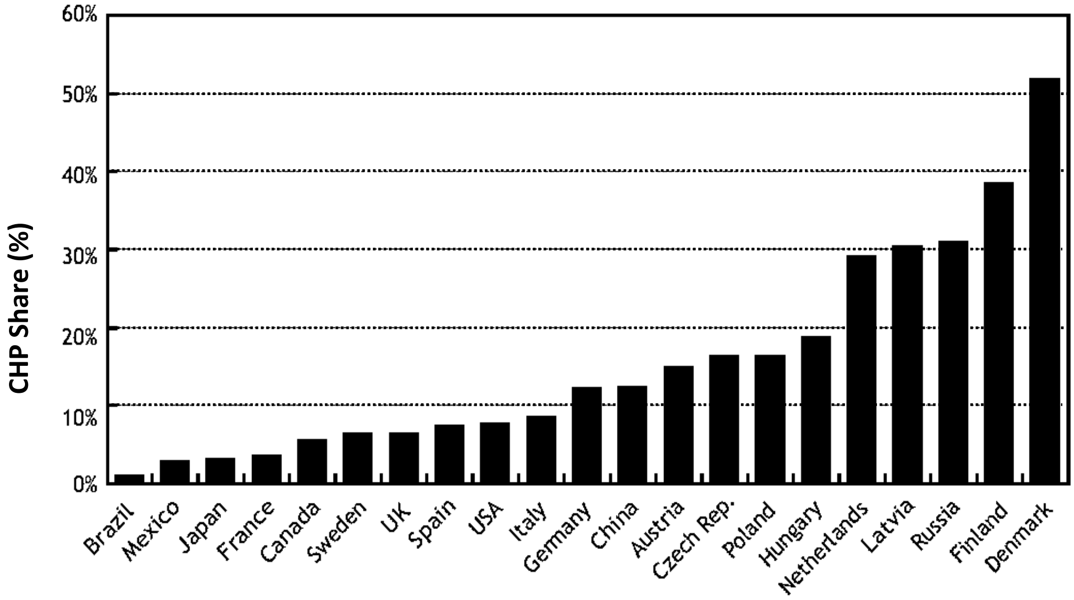

Figure 2.5: CHP share of total national power production. (Data merged from years 2001, 2005, 2006) [21].

However, the highly integrated system of CHP and DH operates at low cost so that earning of a huge amount of money is possible [22]. A number of advantages DH systems offer including [21-23]:

- **Flexibility of fuel use:** In DH system, one of the prominent advantages is a wide range of fuel usage. Co-firing (blending of different fuels) of cheap fuel contributes in economic advantage in DH system.

- **Usage of waste heat:** Opportunities related to using waste heat for generating hot water for residential heating has enabled DH system to incorporate with CHP plant.

- **Co-generation for economic benefits:** Establishment of power plant and district heating together bring the economic benefits into light. Unit investment, operational and maintenance cost gradually declines compared to single unit. Furthermore, thermal efficiency is usually high in CHP plant.

- **Better environment in urban area:** While generating electricity and usable heat from the single CHP plant, various environmental parameters of air, water and soil quality will be better. Less pollution from a CHP plant is one of the promising characteristics from environmental view [24].

- **Higher efficiency:** The CHP plant for co-generation has higher net efficiency than a conventional power plant. The net efficiency for CHP plant ranges 80%-90%, whereas the normal power production unit has comparably lower efficiency like 30%-50%.

As, limit imposes for electricity generation due to heat demand in DH system, CHP plant gives the opportunities to earn a high profit in electricity generation keeping high electricity to heat ratio when electricity price is high [24]. In contrary, the DH suppliers are facing some business issues like reducing their business to some extent. Reducing heat demand for implementation of different energy conservation measures, increased number of low-energy houses and finally comparably hot and warm climate. However, this problem can be eliminated with a CHP plant where a trade-off is balanced between DH system and electricity production. Converting process technologies between electricity and DH system leads a reduction trend of resource utilization and greenhouse gases emission [25].

2.6 Oxygen storage system

Oxygen storage system in oxyfuel combustion method is a relatively new concept. In oxyfuel combustion, pure O_2 is required that ASU produces. Due to high electricity consumption by this unit along with power plant, the concept of the O_2 storage system is considered. Liquid O_2 storage may be better solution where oxyfuel based power plant can use stored O_2 considering demand and production of electricity in relation to boiler load. It is also possible to switch from the oxyfuel-based combustion to air firing mode within short time if ASU fails to operate. Moreover, O_2 storage system with electricity price is also now as new research area to explore. Power plant and ASU for continue O_2 production along with the storage system can be significant option in future [1].

2.7 Carbon capture and storage

2.7.1 Processing of CO_2

The CO_2 stream will be transported through the pipeline. Before passing to pipeline and reservoir, it should be specified with pressure and temperature. High pressure is recommended for overcoming the frictional and static pressure drops. Furthermore, it is essential to conduct precaution of risk of flashing of gas in the whole process. For conditioning the CO_2 flow, the suggested ranges of pressure include 80-120 bar and temperatures 0-50 °C. The temperature should be above the critical temperature of CO_2 (31.1 °C) [1].

2.7.2 Compression of CO_2

Acquiring CO_2 from flue gas and compression requires intensive energy like operation of oxygen production in ASU. Usually, electrical efficiency declines approximately 2-3% point. The factors like compressor efficiency, a significant amount of impurities in CO_2 lead the changing of power consumption in CPU.

Figure 2.6 shows the interface between CO_2 capture and storage [26].

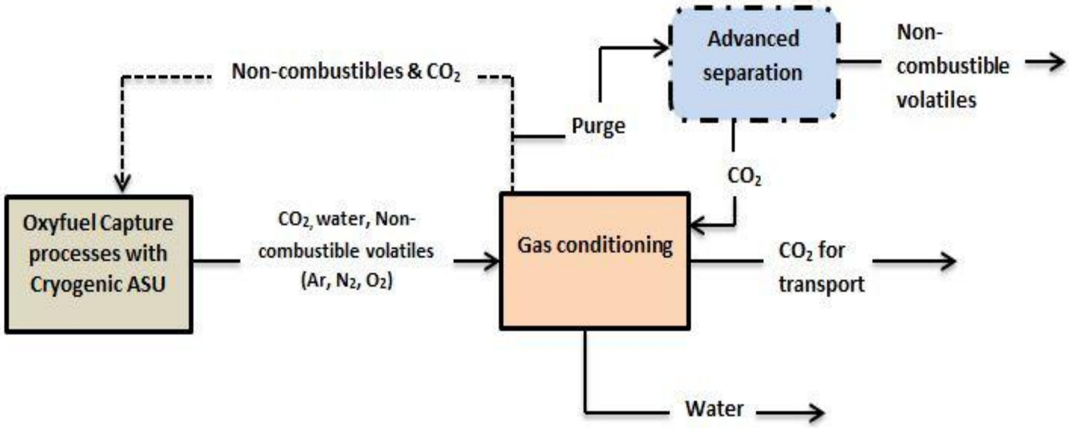

Figure 2.6: Interface between CO_2 capture and storage [26].

2.7.3 Transportation of CO_2

Transportation of CO_2 is possible through pipelines and ship in form of gas as well as through pipelines, tanker and ships as a liquid form. From economic perspective, pipelines as a medium of CO_2 transport are cost effective. Similarly, 1-5 Mt of CO_2 can be transported in a year over 100-500 km [2].

2.7.3.1 CO_2 transportation by pipeline

Transportation of supercritical CO_2 through pipeline is proved technology. 50 Mt of CO_2 is transported per year by long-distance pipeline of 5600 km (diameters up to 0.762 meters) all over the world.

Dehydration is executed before passing into pipelines in relation to reduce corrosion risk and dry CO_2 cannot be activated for corrosion due to steel made pipelines. The largest Cortez pipeline in United States can handle 30 Mt of CO_2 over 800 km per year. On the other hand, projection for Europe is considering that 30000 km-150000 km of pipeline is required for transporting CO_2. In several technical papers, the estimations for CO_2 transportation range from USD 2/t CO_2 to USD 6/t CO_2 (100 km/year) for 2 Mt. However, prices differ from USD 1/t CO_2 to USD 3/t CO_2 (100 km/year) for 10 Mt [2].

2.7.3.2 CO_2 transportation by Ship

CO_2 can be transported by ship with a capacity of 10 kt to 50 kt and flexibility of collection and gathering product from different sizes of sources. It turns the reduction for the infrastructure capital cost. While transportation by ship, compressed natural gas (CNG) carriers or semi-refrigerated tank is used. The cost for transportation in ship ranges from USD 15 (for 1000 km) to USD 30 (5000 km) per ton of CO_2 [2].

2.7.4 Storage of CO_2

IPCC demonstrate three mechanisms for CO_2 storage in their report. Those trapping mechanisms are as follows [2]:

1. **Physical trapping:** Physical trapping refers to the immobilization of gaseous or supercritical phase of CO_2 that can be trapped in the geological formation of two types; namely, static trap that takes place in the structural trap and porous structure keeps residual gas.

2. **Hydrodynamic trapping:** CO_2 with very low motions may migrate upward and can be kept in intermediate layer. This mechanism is better for vast quantities of CO_2. This mechanism limits the risk of leakage from the formation [1].

3. **Chemical trapping:** In this type of storage mechanism, CO_2 is trapped by the ionic trapping or dissolution with water or hydrocarbon. Besides, chemical reaction happens with mineral that refers mineral trapping. Similarly, CO_2 is adsorbed on the mineral surface as called adsorption trapping.

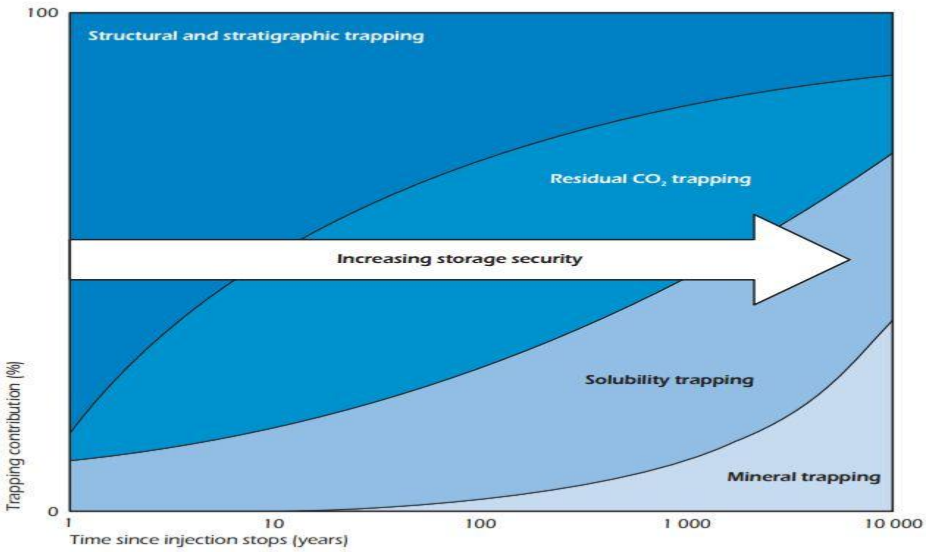

Figure 2.7: Trapping mechanism and timeframe for CO_2 storage [2].

Figure 2.7 represents the different types of trapping mechanisms those have been mentioned before. The physical trapping is considered as the key mechanism under the injection period retains several decades. However, with no risk of leakage phenomenon, CO_2 storage lasts for hundreds or thousands of years [2].

3 Methods

3.1 System description

The technologies that are developed for CO_2 capture and sequestration from coal-fired plants including: CO_2 capture from conventional plants by scrubbing the flue gas, oxyfuel combustion and IGCC with an air separation unit to provide O_2 [6]. However, in the present analysis the proposed power plant considers the following concepts:

- Co-firing with coal and biomass
- Oxyfuel combustion with recirculation of flue gas
- CO_2 capture by conventional compression process
- Storage of oxygen for linking of grid electricity price.

Finally, connecting all these concepts together in one power plant will be very interesting from optimization points of view considering both sustainability and economic factors.

The proposed system is a conventional power plant developed in simulation software Prosim 5.6 where standard tools with CFB boiler, steam turbines and necessary arrangements for oxyfuel combustion, flue gas recirculation and CO_2 capture have been included [27].

The main components of the proposed power plant are:

- Air Separation Unit (ASU)
- CFB boiler with air-preheater and economizer
- Steam turbines with high pressure (HP), intermediate pressure (IP) and two low pressure (LP) modules
- District heating source by taking tapping after first LP turbine
- Compression and purification unit (CPU).

The characteristic of the each subsystem is described below:

3.1.1 Air Separation Unit (ASU)

The Air separation unit (ASU) will separate atmospheric air into its primary components, typically O_2 and N_2. Among various technologies in the separation process, cryogenic distillation technology is used in this proposed plant. The separated oxygen from this unit will be directly provided to the boiler burner that acts as a secondary air for the combustion.

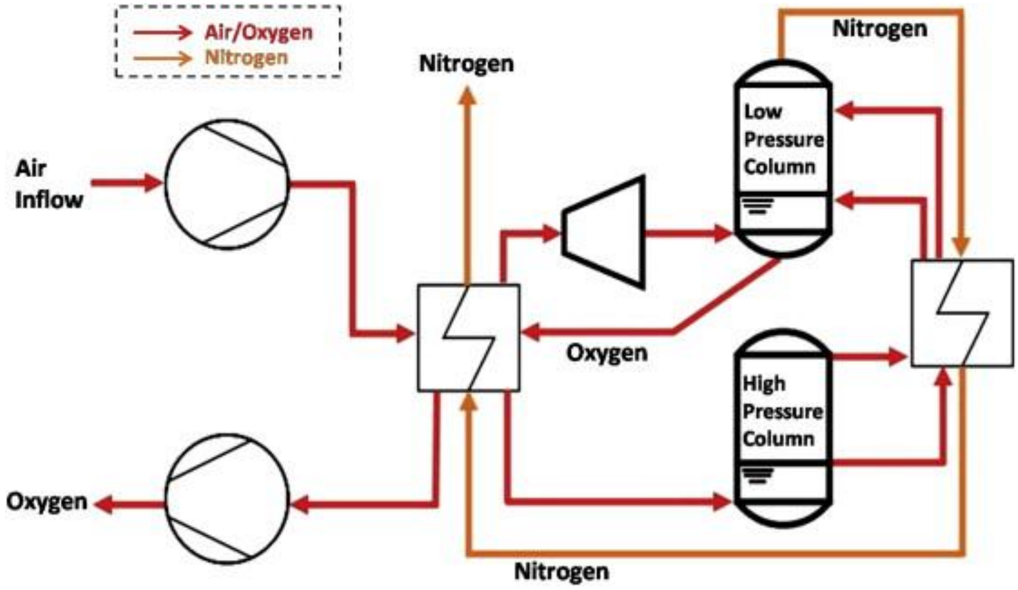

Figure 3.1: Air separation unit (ASU) with two pressure columns [29].

The cryogenic separation process requires an integration of low-pressure column (LPC) and high-pressure column (HPC). The air is first compressed, and then the pressurized air is liquefied to separate O_2 and N_2 in turn in the columns according to their boiling temperatures. This ASU is a very energy intensive unit and electricity consumption proportionally increases with the purity of O_2 [28-29].

3.1.2 Circulating Fluidized Bed (CFB) boiler

The fluidized bed boiler consists of a sand bed where fuel is introduced and combusted. The combustion air blows through the sand bed from an opening at the bottom of the bed. The main advantage of these types of boilers is the fuel flexibility. Biomass can also be co-fired with low-grade coal. In this case, the special designed burners are used with a provision to incorporate 70 % recirculation of flue gas along with fuel (coal and biomass) and combustion air.

The simulation model of CFB boiler consists of five parts: burner, superheater (2 nos.), economizer, air preheater and evaporator. In the burner module, the parameters that are incorporated are fuel (coal and biomass), secondary air (pure O_2 from ASU) and 70 % recirculated flue gas. In an actual power plant, the mixture of recirculated flue gas in the burner needs a lot of auxiliary systems and connections. The separated O_2 is preheated in air preheater to have temperature close to the recirculated flue gas. Moreover, in conventional power plants, the temperature of the air (oxygen) is increased by recovering heat from flue gas to enhance boiler efficiency. Two sets of superheater namely, primary and final superheater are used to produce superheated steam that will drive the steam turbine. The feed water generated from the condensation of steam is preheated in economizer with the exit flue gas to improve boiler efficiency. In the evaporator, the steam water mixture is formed by recovering heat from combustion and finally, the steam is separated in the boiler drum and sent directly to superheater for further superheating.

3.1.3 Steam turbine

There are four modules of steam turbine namely; HP, IP and two LP turbines incorporated in the system to generate electrical power. Two extractions are taken for feed heating system – one from IP turbine exit, and the other one is from an intermediate stage in the first LP turbine. A considerable part of steam (around 75% at full load condition) from the exit of first LP turbine is used to supply heat for district heating system.

3.1.4 District heating system

The concept of combined heat and power plant adopts to increase the overall efficiency of the co-generation power plant. In a conventional condensing power Plant, a huge quantity of heat is wasted in the condenser. Therefore, the proposed concept will utilize the heat to fulfill the district heating need and enhances the overall efficiency of the plant.

3.1.5 Carbon capture in the process model

In the process model, the calculation for carbon capture in compression and purification unit has been executed separately. The standard process diagram illustrates the capture and purification in the power plant [1]. In this model, the power consumption for CPU unit is 149 kWh/t CO_2 [30].

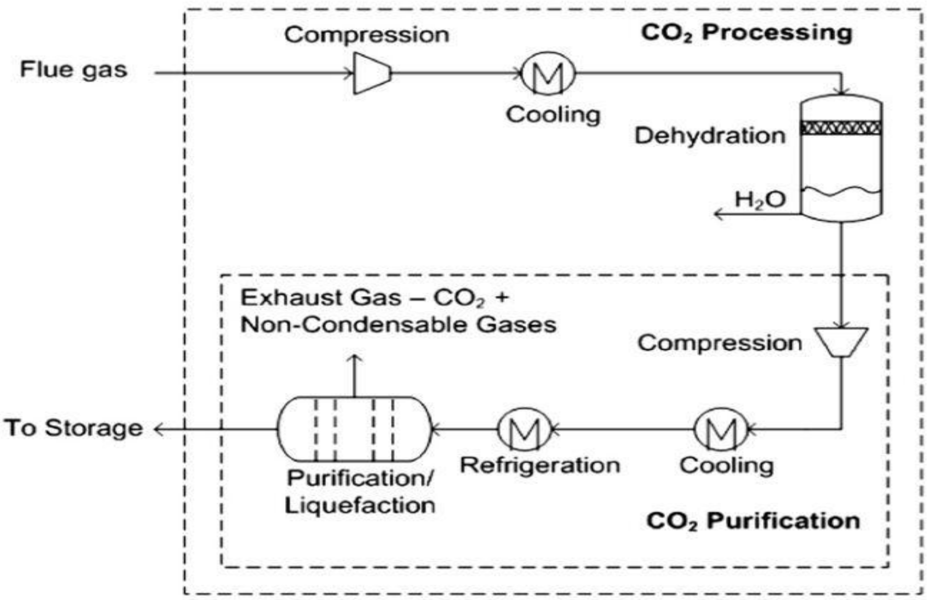

Figure 3.2: Process diagram for CO_2 processing and purification [1].

3.2 Simulation tool: Prosim process model

After constructing the process model with simulation software Prosim 5.6, various parameters and data have been selected and assumptions have been considered based on literature review, objectives and goal of this proposed power plant. These data were inserted into the Prosim model for simulation. The following works have been performed for simulation activities.

1. Preparing the Process model with Prosim
2. Selection and verification of data to be used
3. Parameters identification
4. Assumption taken with consideration of literature review
5. Four design cases selection within the same process model
6. Conversion of design model to off-design mode
7. Changing parameters (DH load and fuel blend) in every design case
8. Simulation run and cross checking the data for validation.

3.2.1 Blend of fuel in process model

In this process model, fuel blending for co-firing has been categorized into four types. Every type is denoted as ‘Fuel mix’. Every fuel mix has the different percentage of coal and biomass. However, the total percentage will always be 100%. Table 3.1 represents the four types fuel mix considering coal and biomass value.

Table 3.1: Blend of coal and biomass used in process model.

Blend of fuel	Coal	Biomass
Fuel mix 1	100%	0%
Fuel mix 2	95%	5%
Fuel mix 3	90%	10%
Fuel mix 4	85%	15%

Table 3.2 shows the fuel analysis of coal and biomass used in this process model. Analysis has been given in dry basis. Default value of the simulation programme has been used. From Table 3.2, it is noticeable the biomass contains a high percentage of O_2 (42.5% dry wt.) whereas coal has low content of O_2 (9.1% dry wt.). Due to high content of O_2, biomass has low energy density, and higher moisture also lowers the energy content [19]. Furthermore, high moisture content in biomass accounts for moderate level of carbon.

Table 3.2: Fuel analysis of coal and biomass.

Analysis in dry basis (wt.%)	Coal	Biomass
C	73.2	50.4
H	4.7	6.2
S	1.0	0.0
O	9.1	42.5
N	1.0	0.5
Ash	11.0	0.4
Water (% of total fuel)	9	55
LHV	29.31	18.80

3.2.2 Designing parameters for DH load in process model

An estimated load duration curve from the adopted empirical data has been generated for providing input data to process model In the process model, the plant was designed to be the base load plant in the DH network. Futhermore, it was assumed that the the maximum heat generation of proposed plant will be 90% of peak head demand (Appendix C, [31]). In this case, 100% DH load for the process model is 588 MW_{th}. In Table 3.3, load of DH, DH load and extracted steam for DH have been shown.

Table 3.3: DH load at plant side for process model.

Load of DH (at plant side)	DH load* (MW)	Extracted steam at DH (kg/s)
100%	588	280
90%	529	252
80%	470	224
70%	412	196
60%	353	168

*Value may be ± 5MW due to simulation in off-design as mass of steam was first given as parameter and DH load was calculated afterwards.

3.2.3 Design cases for process model

Four design cases have been prepared based on fuel mix (1-4) and DH load (60-100%). Simulation process on Prosim software has been executed on these four design cases. Every fuel mix (1-4) and DH load (60-100%) have been changed and simulated in four design cases regardless their base designing parameters. For instance, design case 1 was prepared based on fuel mix 1 (100% coal) and 90% DH load. However, in the simulation process for design case 1, every fuel type and DH load have been changed and simulated separately in off-design mode. Simulation process was identical for all design cases. Table 3.4 represents the four design cases with their combination of designing parameters of fuel mix and DH load.

Table 3.4: Design cases based on fuel mix and DH load.

	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
DH load 100%				
DH load 90%	Design Case 1			Design case 2
DH load 80%				
DH load 70%	Design Case 3			Design case 4
DH load 60%				

Figure 3.3 illustrates the conceptual process model for oxyfuel based CHP plant with CCS, which has been constructed in Prosim 5.6 software.

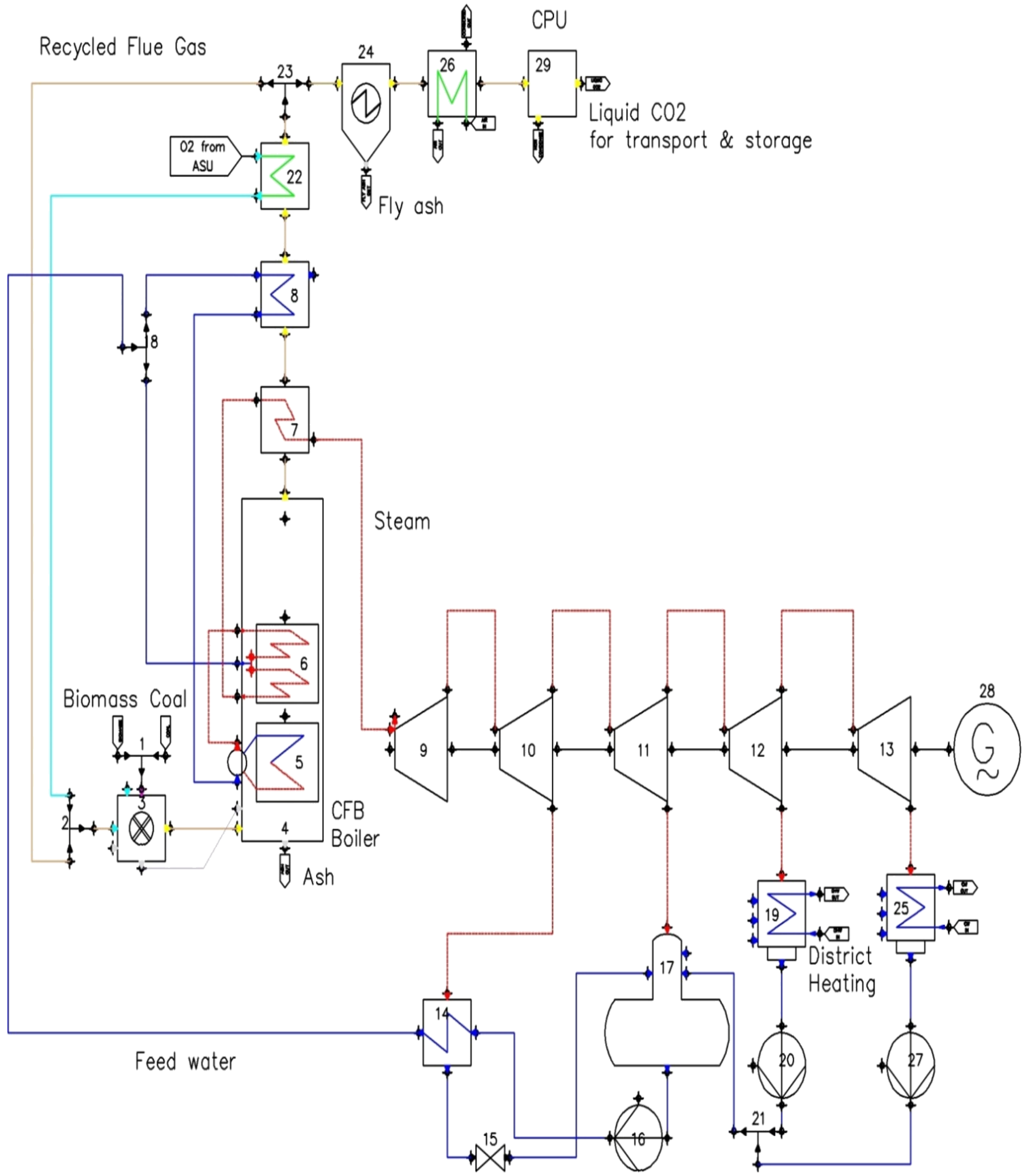

Figure 3.3: The proposed CHP power plant with CCS (designed and simulated by Prosim Software).

1/2/21: Mixer	8: Economizer	17: Feedwater tank	28: Alternator
3: Burner	9-13: Turbine stage	18/23: Splitter	29: CPU
4: Boiler Bed	14: Preheater	19/25: Condenser	
5: Evaporator	15: Regulatory valve	22/26: Heat exchanger (gas/gas)	
6-7: Superheater	16/20/27: Pump	24: Electrostatic precipitator (ESP)	

[* Module 29: CPU and ASU were simulated externally].

Table 3.5: Assumption of parameters and data input.

Parameters	Unit	Value used
Fuel		
Coal[1]	kg/s	34-40
Biomass[1]	kg/s	0-6
Temperature at fuel input	°C	20
Pressure at fuel input	bar	1
Air composition		
O_2	mol%	79
N_2	mol%	21
ASU[2]		
O_2	mol%	95
N_2	mol%	5
Excess air		1.1
Temperature of O_2 (after preheater)	°C	100
CFB		
Average bed temperature[3]	°C	800
Burning efficiency[3]		100%
Boiler efficiency		95%
Steam cycle		
Turbine isentropic efficiency[3]	%	93-97
Pump efficiency[3]		80
Temperature/Pressure	°C/bar	
Steam in		500/70
Steam out		
1^{st} extraction to preheater		240/10
2^{nd} extraction to feed water tank		165/5
3^{rd} extraction to district heating		105/1.17
4^{th} extraction to condensing		36/.06
DH		
Temperature of Water in	°C	45
Temperature of Water out	°C	100
Thermal temperature Diff (TTD)[3]	°C	4
ESP		
Separation Factor[3]		100%
Electricity consumption[4]		
Air Separation Unit (ASU)	kWh/tO_2	212
Compression & Purification unit (CPU)	kWh/tCO_2	149

[1] Fuel mix (1-4) represents different value [Table: 3.1]. [2] Due to no availability of argon (Ar) in Prosim software, N_2 was used.
[3] Default value of Prosim software was used in these parameters. [4] Ref: [30].

All data as input and assumptions have been shown in Table 3.5. In addition, the following parameters represented in Table 3.6 have been considered as key process parameters. In Chapter 2, these parameters have elaborately discussed considering their significance in the oxyfuel combustion with CCS. In the process model, the corresponding values used and their ranges have been shown separately. In Table 3.6, the value under ranges category is considered as reference value [11].

Table 3.6: Key process parameters for Prosim model.

Parameter	Units	Used values	Ranges
Oxygen purity	% mole	95	90-100
Excess oxygen	% theor.	3	0-19
Flue gas recycle ratio	fraction	0.7	0.6-0.85
Flue gas recycle temperature	°C	130-138	100-300
Flue gas moisture removal	%	0 (wet recycle)	0-100
CO_2 product purity	% mole	92	90-100

3.3 Optimization tool: GAMS Model

Optimization process of the overall power plant system is a difficult and challenging task. A trade-off plays a vital role in decision-making process including supply technologies and mitigation of environmental pollutants as well as CO_2 emission. Several factors like economic variability, stress on environment, nature of operations and construction time also lead the supply option. Furthermore, the ultimate goal is minimizing overall cost [32].

A deterministic optimization model has been constructed to investigate several parameters for the overall power plant with CCS. Likely, this model considers the prices of fuel, electricity, district heating and particular time and cases dependent variables generated by Prosim software to optimize the O_2 storage system for 1-year period. Moreover, optimal mix of fuel (coal and biomass) with different district heating load has been derived from the GAMS model for this proposed power plant.

3.3.1 Formulation of model

The GAMS model consists of statements written in GAMS language. As input, sets, data (parameters and tables), variables, equations, models, and solve statement are defined and written in the form of text in GAMS model. Furthermore, GAMS tool considers two features: declaration and definition. Declaration refers to something exists with a particular name and definition indicates a specific value is given to that particular object [33].

Table 3.7 and 3.8 represent indices used and set required in the model respectively where sets are defined as basic building block for GAMS model and qualitatively equivalent to indices in relation to algebraic illustration of model [33].

Table 3.7: Indices used in model.

Indices	Description
t	time period
fuelmix	fuel mixture

Table 3.8: Sets required for the model.

Sets	Description
T	$= \{t\}$ t is the time period
FUELMIX	$= \{fuelmix\}$ fuel mix is the fuel mixture of coal & biomass

Table 3.9 represents parameters used in GAMS model where each parameter is defined with text, unit and reference value executed in the model.

Table 3.9: Parameters used in GAMS Model.

Parameter	Description	Units	Value
PDH	District heating price	€/MWh	35
FUEL1	Biomass cost	€/MWh	18.5
FUEL2	Coal cost	€/MWh	31.6
HVBIO	Heating value of biomass	MJ/kg	18.80
HVC	Heating value of coal	MJ/kg	29.31
PCO_2CAP	Selling price for captured CO_2	€/ton	20
MINASUF	Minimum mass flow of O_2 through ASU	kg/s	Value to be calculated
QDD (fuelmix, t)	DH load	MW	Appendix 3
PEL (fuelmix, t)	Electricity price	€/MWh	Appendix 4
MBIO (fuelmix)	Mass flow of biomass in every fuel-mix	kg/s	(0,2,4,6)
MC (fuelmix)	Mass flow of coal in every fuel-mix	kg/s	(40,38,36,34)
O_2NEED (fuelmix)	Total O_2 required for plant	kg/s	Appendix 2
MFLUE1(fuelmix)	Flue gas flow in each Fuel-mix	kg/s	Appendix 2
PERIOD	Time of each period	hours	6

The real value for economic parameter used in the process model has been obtained from the Finnish energy market. District heating price from Energiateollisuus ry [34], electricity price from NordPool [35], cost of biomass (wood chip) and coal from Statistics Finland [36] and finally, CO_2 selling price for carbon trading from Bloomberg New Energy Finance (Directorate-General for Climate Action, European Commission) [37] represent the actual data for Finland in the year of 2011.

Positive variables in GAMS model have been shown in Table 3.10. These decision variables have been declared with a statement and units.

Table 3.10: Positive variables in GAMS Model.

Positive variable	Description	Units
elnet(fuelmix,t)	Electricity produced in power plant	MW
elCO_2comp(t)	Electricity consumed in CO_2 compression	MW
elasu(t)	Electricity consumed in ASU	MW
elstg(t)	Electricity consumed in Storage	MW
m1O_2asu(t)	O_2 flow out of ASU	kg/s
m2O_2asu(t)	O_2 flow out of ASU	kg/s
mO_2stgin(t)	O_2 flow into O_2 storage	kg/s
mO_2stgout(t)	O_2 flow out from O_2 storage	kg/s
O_2levstg(t)	Level of O_2 in storage	kg/s
totO_2(fuelmix,t)	Total O_2 need	kg/s

3.3.2 Objective function

Objective function maximizes the profit in selling of electricity as well as buying of fuel (fuel usage). Eq. (1) shows the structure of objective function that is denoted as 'z' and the corresponding equation has been illustrated as follows:

$$z = PERIOD \times \sum_{fuelmix} \sum_{t} \Big(PEL_t \times elnet_{fuelmix,t} + PDH \times QDD_t - PEL_t \times elCO2comp_t - PEL_t \times elasu_t - PEL_t \times elstg_t - FUEL1 \times HVBIO \times MBIO_{fuelmix} \times y_{fuelmix,t} - FUEL2 \times HVC \times MC_{fuelmix} \times y_{fuelmix,t} + \frac{PCO2CAP \times 0.8723 \times MFLUE1_{fuelmix}}{3.6} \Big) \quad (1)$$

3.3.3 Equations for GAMS model

Equations in GAMS models require to be declaring and defining in the statement. Equations are major power in the algebraic modeling language GAMS [33].

Eq. (2) shows the calculation for the power consumption in Air Separation Unit (ASU) [11]:

$$elasu_t = 0{,}7632 \times m1O2asu_t; \quad t \in T. \tag{2}$$

Power consumption in carbon compression and purification unit (CPU) is expressed by Eq. (3) [11]:

$$elCO2comp_t = 0.5364 \times 0.8723 \times \sum_{fuelmix}\left(y_{fuelmix,t} \times MFLUE1_{fuelmix}\right);$$
$$fuelmix \in FUELMIX, t \in T. \tag{3}$$

Eq. (4) defines the power consumption in O_2 storage and corresponding equation is as follows:

$$elstg_t = 0.001 \times 225.1 \times mO2stgin_t; \quad t \in T. \tag{4}$$

Eqs. (4-8) represent power generation in every fuel mix (blend of coal and biomass)

$$elnet_{fuelmix=1,t} = y_{fuelmix=1,t} \times (-0.0751 \times QDD_t + 353.75);$$
$$fuelmix \in FUELMIX, \ t \in T. \tag{5}$$

$$elnet_{fuelmix=2,t} = y_{fuelmix=2,t} \times (-0.0884 \times QDD_t + 343.75);$$
$$fuelmix \in FUELMIX, \ t \in T. \tag{6}$$

$$elnet_{fuelmix=3,t} = y_{fuelmix=3,t} \times (-0.0932 \times QDD_t + 335.56);$$
$$fuelmix \in FUELMIX, \ t \in T. \tag{7}$$

$$elnet_{fuelmix=4,t} = y_{fuelmix=4,t} \times (-0.1022 \times QDD_t + 327.32);$$
$$fuelmix \in FUELMIX, \ t \in T. \tag{8}$$

Through the execution of GAMS Model, only one type of fuel mix for each period was operated and Eq. (9) derives for the respective purpose.

$$\sum_{fuelmix} y_{fuelmix,t} = 1; \quad \text{fuelmix} \in \text{FUELMIX}, \text{t} \in \text{T}. \tag{9}$$

The mass flow of O_2 required to the boiler for combustion of fuel is sum of the mass of O_2 from ASU to burner $(m2O2asu_t)$ and O_2 from storage $(mO2stgout_t)$. Eq. (10) defining the total oxygen requirement is as follows:

$$\sum_{fuelmix} y_{fuelmix,t} \times O2NEED_{fuelmix} = m2O2asu_t + mO2stgout_t\ ;$$

$$\text{fuelmix} \in \text{FUELMIX}, \text{t} \in \text{T}. \tag{10}$$

Eq. (11) shows the mass of O_2 from ASU splitting into two streams. For the better optimization in GAMS Model, one O_2 stream is denoted as O_2 flow into storage $(mO2stgin_t)$ and another stream as O_2 from ASU to burner $(m2O2asu_t)$.

$$m1O2asu_t = mO2stgin_t + m2O2asu_t; \quad \text{t} \in \text{T}. \tag{11}$$

The level of O_2 in the storage system depends on time. To fit the equation, the positive variables like O_2 flow into storage $(mO2stgin_t)$ and O_2 from storage $(mO2stgout_t)$ are considered. Eq. (12) defining the level of O_2 in storage is represented as follows:

$$O2levstg_t = (mO2stgin_t - mO2stgout_t) \times 6 \times 3600 + O2levstg_{(t-1)}; \quad \text{t} \in \text{T}. \tag{12}$$

Usage of biomass in the process model has been limited. Eq. (13) for biomass usage represents as:

$$\sum_{fuelmix} \sum_{t} \left(6 \times MBIO_{fuelmix} \times y_{fuelmix,t}\right) \leq 0.10 \times \sum_{fuelmix} \sum_{t} \left(6 \times (MBIO_{fuelmix} + MC_{fuelmix}) \times y_{fuelmix,t}\right);$$

$$\text{fuelmix} \in \text{FUELMIX}, \text{t} \in \text{T}. \tag{13}$$

3.3.4 Operational methodology of oxygen storage

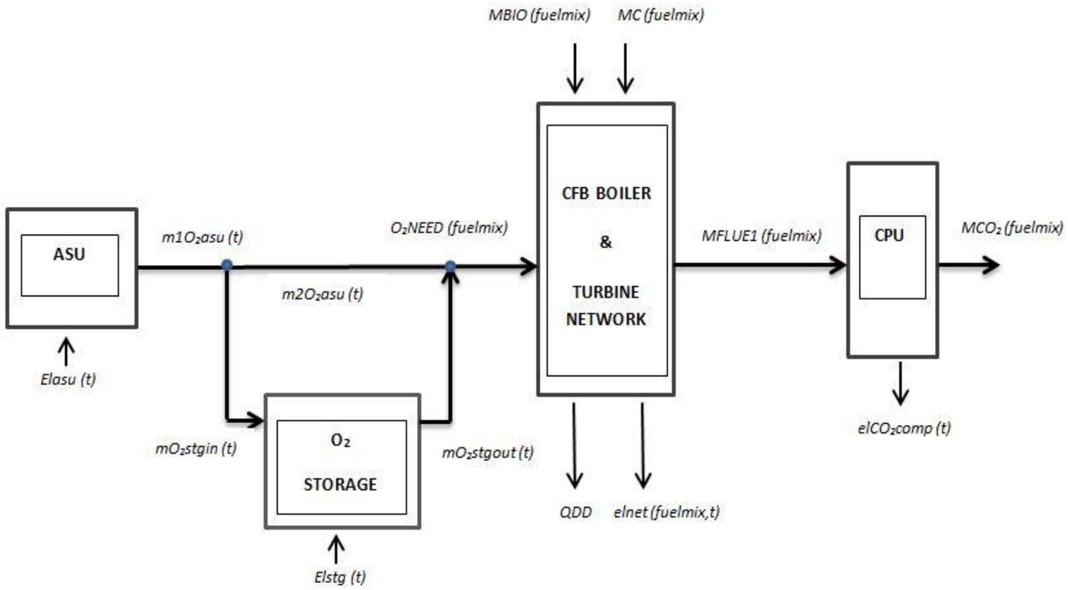

Figure 3.4: Overall system diagram including O_2 storage with parameters and variables (based on Prosim and GAMS model parameters).

Figure 3.4 demonstrates the overall operational methodology of O_2 storage system for proposed power plant. There should be two output lines from the ASU, one will supply O_2 directly to the boiler and another one connects the ASU with the O_2 storage facility. The control mechanism regarding the distribution of O_2 in these two lines will be entirely linked with grid electricity price. Suitable controllers and control strategy will be adopted to execute the economical operation of ASU.

4 Results

4.1 Simulation results from process model

In this section, different curves have been developed to predict the behavior of electricity and DH load for four design cases, built in Prosim by varying the following two parameters:

(a) Fuel mix of coal and biomass

(b) District heating load.

4.1.1 Relation between DH and net electricity

These curves will provide a basis to optimize the plant from both technical and economical point of view.

4.1.1.1 Design case 1: (Fuel mix 1 & DH load 90%)

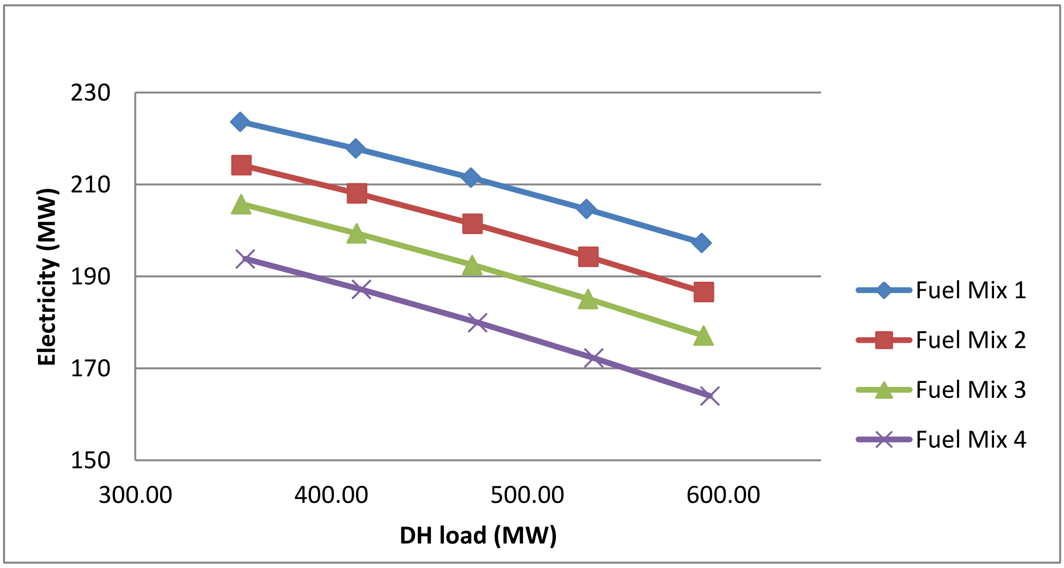

Figure 4.1: Relation between DH load and net electricity for design case 1.

The design case 1 is prepared with fuel mix 1 (100% coal) and 90 % DH load. After creating the design case 1, four types of fuel combination (fuel mix 1- 4), DH loads (60-100%) are simulated on off-design mode in the design case. Figure 4.1 illustrates that the behavior of electricity and DH load follows an inverse relation for all types of fuel mix and at different DH loads. Therefore, it can be concluded that when DH load increases, the electrical power from the plant decreases for all types of operating condition.

4.1.1.2 Design case 2: (Fuel mix 4 & DH load 90%)

Like design case 1, the design case 2 is created from the same process model but changing with fuel mix 2 (85% coal and 15% biomass) and 90 % DH load. Simulation runs in off-design mode with changing the types of fuel combination and DH load. The corresponding curve in Figure 4.2 is developed from the simulation results. In

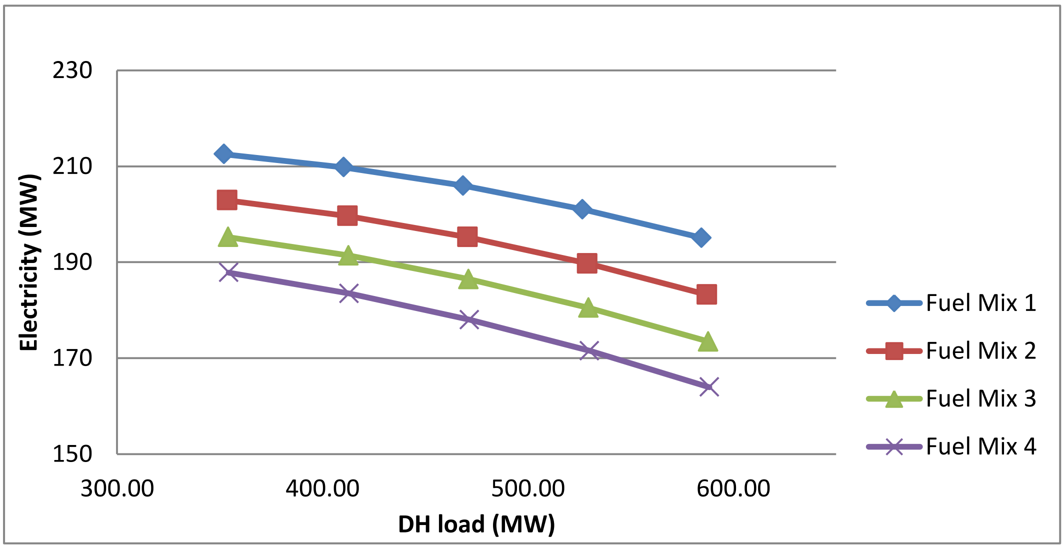

Figure 4.2: Relation between DH load and net electricity for design case 2.

this case, the behavior of electricity and DH load follows an inverse relation with little bit polynomial nature for all types of fuel mix and at different DH loads. The power generation from design case 2 is less than design case 1 for all types of fuel mixes and different DH load. For instance, the DH and electricity generation for design case 1 are 589.16 MW_{th} and 197 MW_e respectively (100% coal firing and 90% DH load) while bit decreased value for design case 2 is shown as 584.59 MW_{th} and 195.07 MW_e respectively (same coal firing and DH load).

4.1.1.3 Design case 3: (Fuel mix 1 & DH load 70%)

The design parameter for case 3 is fuel mix 1 (100% coal firing) and 70 % DH load. Running the simulation process is similar to design case 1 and 2. Fuel combination as Fuel mix and DH load are simulated and the corresponding curve is shown in Figure 4.3.

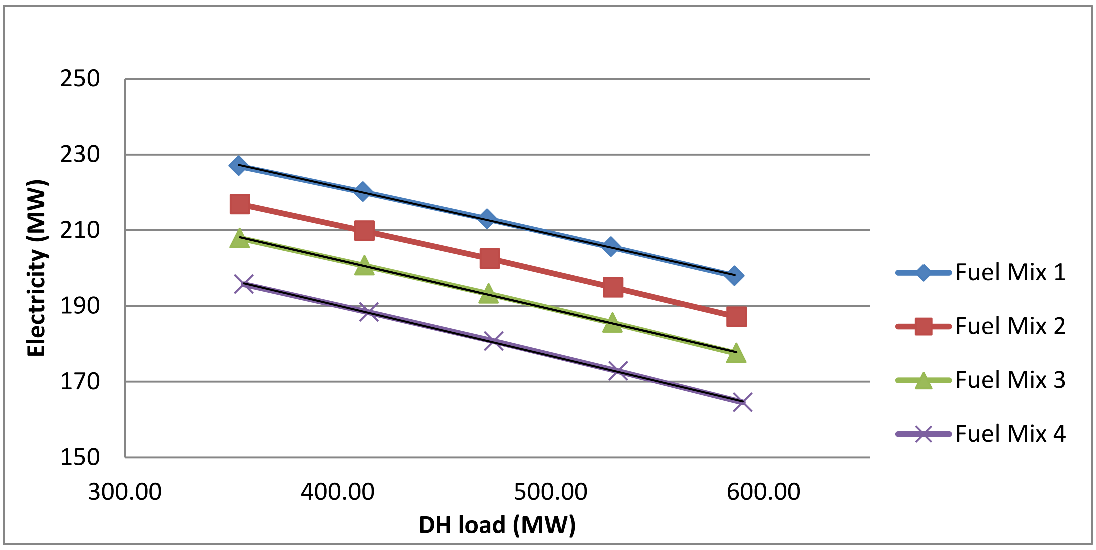

Figure 4.3: Relation between DH load and net electricity for design case 3.

Figure 4.3 for design case 3 demonstrates the inverse behavior of electricity and DH load for all types of fuel mix and different DH loads. Interestingly, the power generation from this design case is almost equivalent to design case 1. The difference between these two cases is the change in DH load. However, more electricity is generated in design case 3 than design case 1 in case of fuel mixes (3-4). For example, electricity generation in design case 1 and case 3 is 193.81 MW_e and 195.71 MW_e respectively (for both case fuel mix 4 and DH load 60%) [Appendix: B]. However, with the increase in DH load the electrical power from the plant decreases in all types of operating condition.

4.1.1.4 Design case 4: (Fuel mix 4 & DH load 70%)

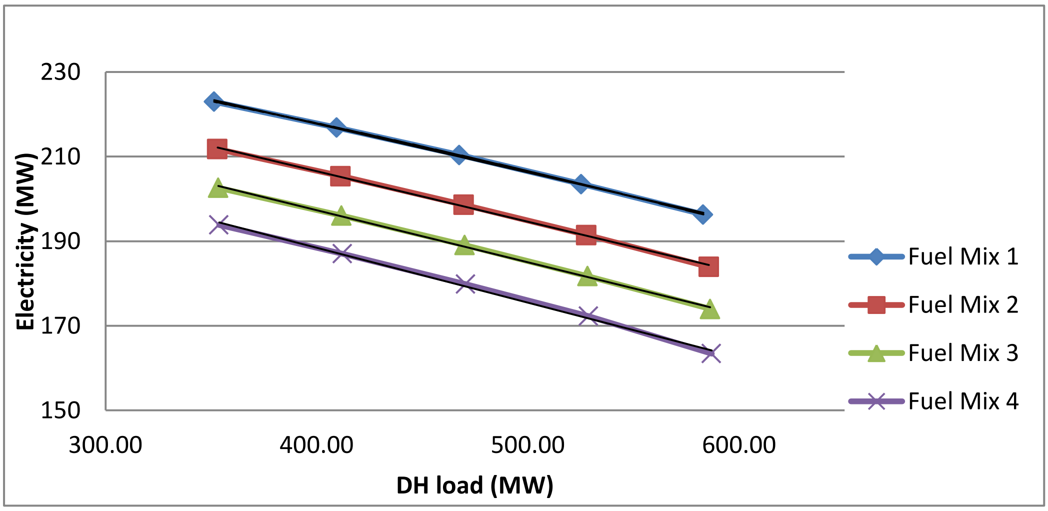

Figure 4.4: Relation between DH and net electricity for design case 4.

Fuel mix 4 (85% coal and 15% biomass) and 70 % DH load are key parameters to construct the design case 4 in the process model. After simulating with different fuel mixes and DH loads in off-design mode, the resultant data is shown as linear curve in Figure 4.4. Like all three previous design cases, this case also demonstrates the inverse behavior of electricity and DH load for all types of fuel mixes and different DH loads. Higher electricity generation is observed in design case 4 compared to design case 2 when the DH load is 60%-70%. In contrast, DH generation is bit higher in design case 2 than in design case 1 for most of the fuel mixes.

The key target behind the development of four design cases for same parameters is to suggest a best and optimized operational scenario for the plant. After a close analysis of the curves, it can be concluded that the design case 3 offers maximum electrical power for a certain DH load for all types of fuel mix.

4.1.2 Net efficiency versus biomass percentage with coal

In the simulation of the process model, net efficiency refers to the combined efficiency of net electrical power and useful heat for district heating. Moreover, the net electricity is considered as the electricity available after electricity consumption for all auxiliaries including ASU and CPU.

4.1.2.1 Design case 1: (Fuel mix 1 & DH load 90%)

In design case 1, the maximum efficiency was found in the operation at off- design mode with DH load 90% and fuel mix 4. Efficiency value accounts for 76%. However, running the model with DH load 60% and fuel mix 1 showed the minimum net efficiency value of 56%. It is clearly observed that net efficiency increases with adding the biomass portion to coal (Figure 4.5). Obviously, net efficiency is higher in Fuel case 4 than rest of the type of mixture.

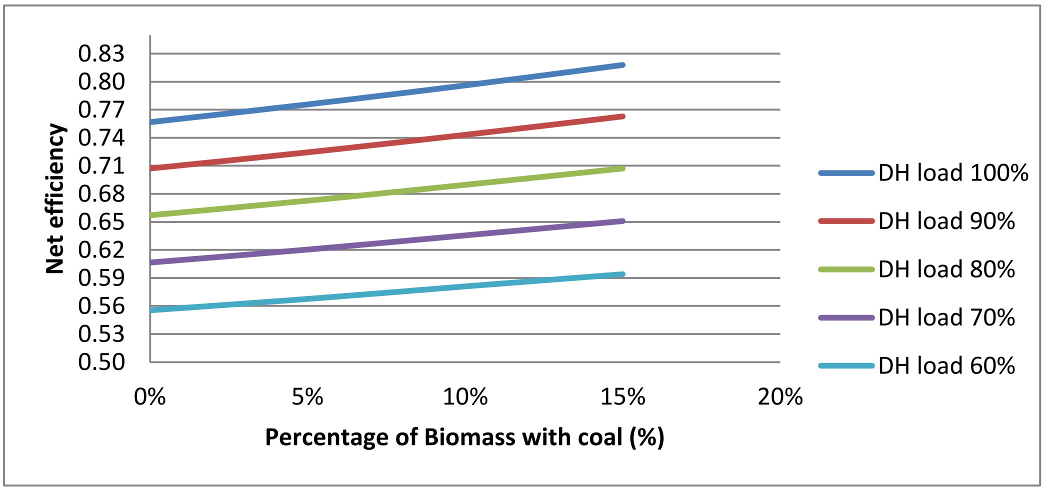

Figure 4.5: Change of net efficiency with biomass percentage (design case 1).

4.1.2.2 Design case 2: (Fuel mix 4 & DH load 90%)

Efficiency decreases by 1% in design case 2 (fuel Mix 4 and DH load 90%) regardless changing DH load and fuel mix. Figure 4.6 represents the graph for design case 2.

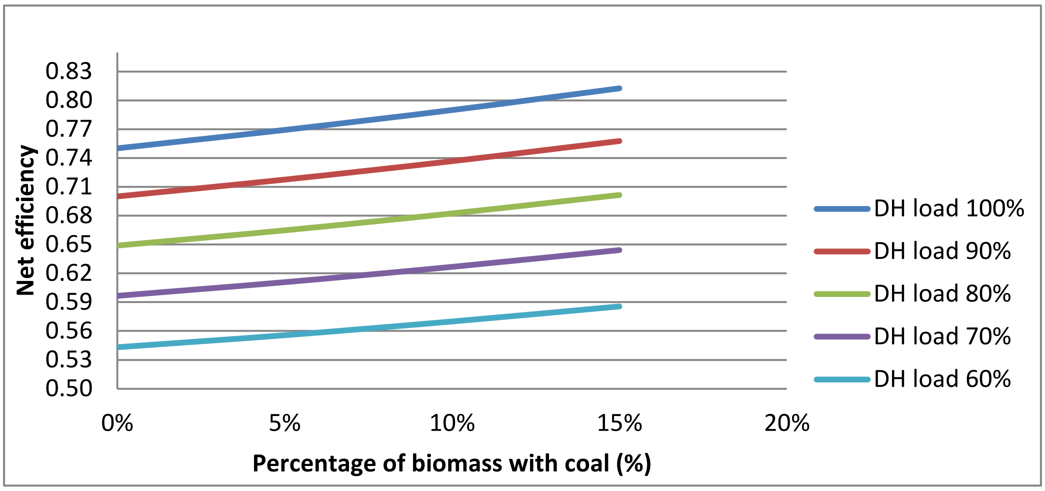

Figure 4.6: Change of net efficiency with biomass percentage (design case 2).

4.1.2.3 Design case 3: (Fuel mix 1 & DH load 70%)

Figure 4.7 for design case 3 illustrates the equivalence efficiency to design case 1. Design case 3 also matches to design case 2 interim of efficiency to some extent.

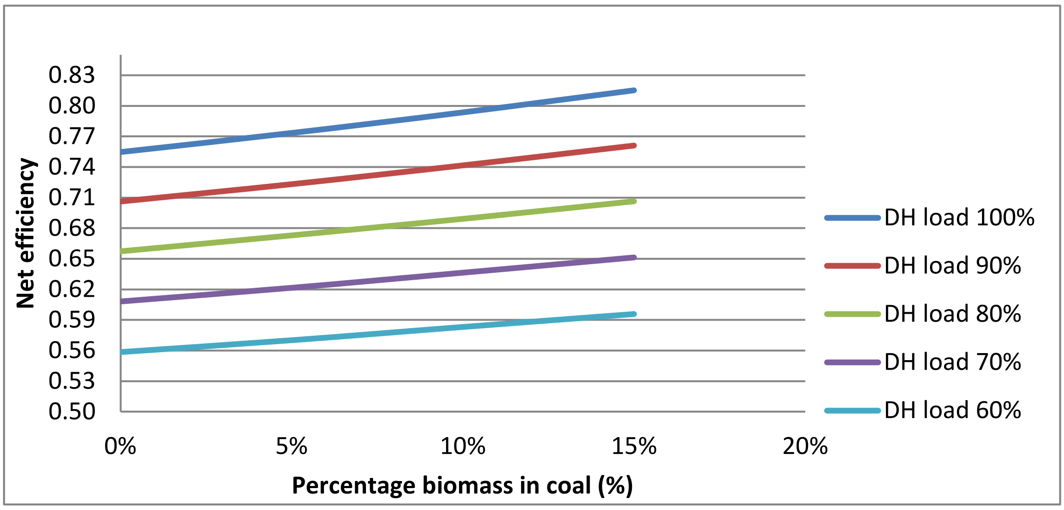

Figure 4.7: Change of net efficiency with biomass percentage (design case 3).

4.1.2.4 Design case 4: (Fuel mix 4 & DH load 70%)

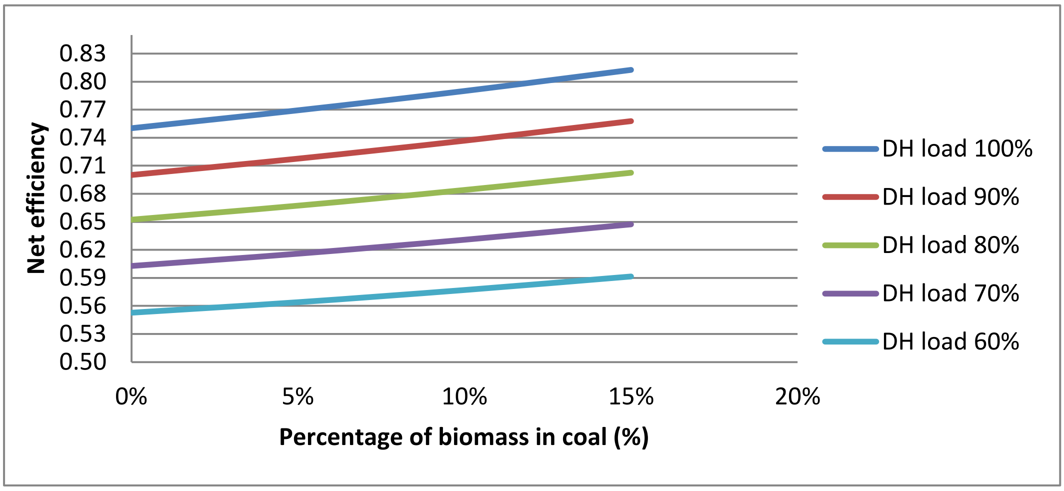

Figure 4.8: Change of net efficiency with biomass percentage (design case 4).

Design case 4 demonstrates the same trend of efficiency that other design cases have shown. Figure 4.8 shows that net efficiency increases with more blending of biomass like the other design cases. In this case, efficiency is close to the efficiency of design case 2.

All the Figures show that there is an increase in net efficiency with the rise of biomass percentage in co- firing with coal. The increasing amount of biomass percentage in co-firing will cause a drop of fuel power which results in electrical power loss because the DH is kept constant. Therefore, a drop of electrical power is favorable to increase the net efficiency. Although the rate of increase of net efficiency (slope of the lines are equal) is same in all DH cases, but the maximum efficiency will be achieved in design case 1 and 3 (in both cases, same fuel mix 1 as design parameter, but DH load is different). Replacing biomass with coal indicates a sense of sustainability because of carbon neutral nature of biomass. The nature of the graphs suggests that a sustainable operational mode of plant also results in the efficiency increase.

Theoretical concepts suggest that it is always economical to reduce the energy conversion chain. In DH case, low-grade energy is used for generating heat thereby reducing one-step in energy conversion. Consequently, it will always be better to use most of the fuel power as heat rather than converting into electricity. Nevertheless, in practical scenario there should be a balance between the utilization of heat and electricity.

The rise of biomass percentages is closely related to the amount of electrical power that can be compromised. Too much compromise on electrical power may not be suitable for some particular cases in the grid. The mix of biomass in co-firing is actually dependent on the grid electricity price and district heating price. A balanced correlation needs to be developed to define the co-firing ratio.

4.1.3 O_2 mass flow versus biomass percentage with coal

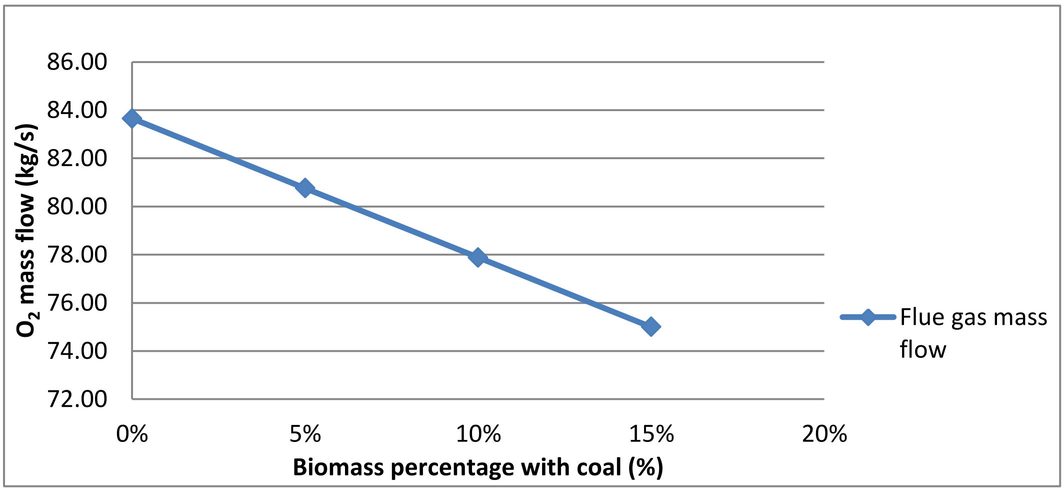

Figure 4.9: Change of O_2 stream with biomass percentage (all design cases).

Figure 4.9 shows that the O_2 requirement from ASU drops with the increase in biomass percentage in the co-firing. From the chemical analysis of biomass, it is found that the carbon content of biomass is less than coal. From the fuel analysis (Table: 3.2), coal used in the process plant has 9.1% O_2 (dry wt.%) whereas biomass (wood chip) O_2 value is 42.5% (dry wt.%). As the carbon content is less in biomass, it is very natural that the oxygen will also drop in combustion. In the process model, O_2 requirement was 93.65 kg/s in 100% coal input. Required O_2 level decreases with addition of biomass and it declined to 75 kg/s, when 15% biomass was added to combust with 85% coal. Therefore, this graph encourages the co-firing of more biomass with coal to reduce the power consumption of ASU.

4.2 Optimization results from GAMS model

4.2.1 Oxygen storage model

In the proposed power plant, ASU for the oxyfuel combustion is the biggest auxiliary in the power plant. As a result, it will be interesting to investigate an economic operational methodology of this high-energy consuming auxiliary equipment with the help of GAMS optimization tools. To optimize the operational load of ASU, the concept of oxygen storage is introduced based on grid electricity price.

In the optimization, Finnish electricity price from NordPool has been taken as reference to link the feasibility of oxygen storage with electricity price. The control or operational methodology for the ASU is as follows:

(a) When the grid electricity price is low then it is advisable to operate the ASU at its maximum capacity, so that a certain amount of oxygen can be stored apart from fulfilling the boiler demand.

(b) The stored oxygen can be used during high grid electricity price.

(c) Suitable control strategy should be adopted to sense the grid electricity price and execute the ASU operation economically.

The market price of electricity for the 2011 taken from NordPool is simulated in GAMS model to develop the yearly trend [35]. The data has been taken at an interval of six hours for the whole year of 2011. The oxygen requirement for the oxyfuel combustion is optimized in GAMS based on the model developed in Prosim 5.6.

Figure 4.10 shows a comparative study of market price of electricity and O_2 storage level for the year 2011. It was observed from the graph that the grid electricity price and the oxygen level follow an inverse relation. When the electricity price declines,

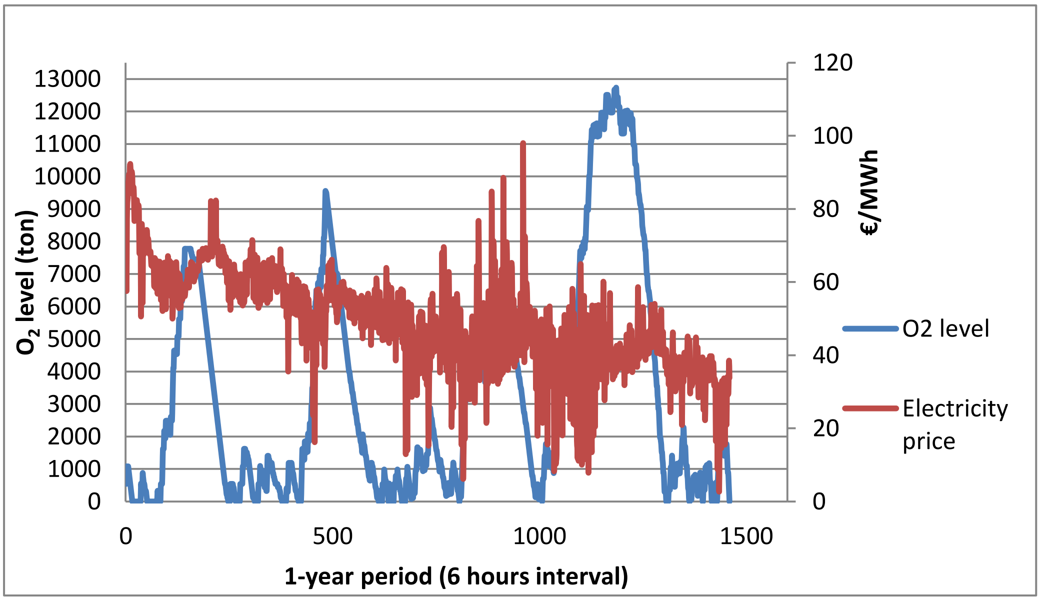

Figure 4.10: Comparison between O_2 storage and electricity price for the year 2011.

the graph indicates that it will be a good consideration to store O_2 and stored O_2 can be used when the electricity price is high. This operational methodology based on the will provide an efficient and cost effective solution for the biggest auxiliary (ASU) in the plant.

4.2.2 Economic evaluation considering O_2 storage

In the thesis work, the economic evaluation has not been analyzed in detail. For the optimization of O_2 storage, the key economic parameters includes the cost of fuel (coal and biomass), market electricity price, district heating price and selling price of captured CO_2 for carbon trading. All the economic data have been taken from Finnish market value for the year 2011 (Table 4.1).

From the optimization of the process model with O_2 storage system, positive value has been derived. However, investment cost and maintenance cost were not considered. It was preliminary assumed that positive value would indicate feasibility of the plant with storage system, otherwise it will not be suggested to use O_2 storage system in case of negative value.

Table 4.1: Economic data used for process model.

Description	Units	Value	References
District heating price	€/MWh	35	[34]
Electricity price	€/MWh	Appendix D	[35]
Cost of biomass (Forest chips)	€/MWh	18.5	[36]
Cost of coal	€/MWh	31.6	[36]
Price for selling captured CO_2	€/ton	20	[37]

Table 4.2: O_2 storage benefit potential for all design cases.

Design cases	With Storage (€)	Without Storage(€)	Storage benefit potential (€)
Design case 1	3,038,951,000	2,959,353,000	79,598,000
Design case 2	3,036,412,000	2,956,806,000	79,606,000
Design case 3	3,039,524,000	2,959,927,000	79,597,000
Design case 4	3,037,718,000	2,958,559,000	79,159,000

From Table 4.2, it is clearly observed the positive value for storage of O_2 in all design cases. Among all four design cases, design case 3 (100% coal and DH load 70%) indicates high profit from the process model considering Finnish market electricity price and average value for district heating price for the year 2011.

The price for CO_2 trading under EU Emission Trending Scheme (EU ETS) ranges from 20 €/ton to 25 €/ton (projection year 2020-30 with real data of 2009), 16 €/ton. In this process model, the assumption for CO_2 price is 20 €/ton [37]. The higher price for CO_2 trading and district heating price will lead the profit in the proposed power plant. In contrast, different prices are fixed in the market for district heating for different European countries. Even, a wide range of DH price (€/MWh) has been offered by DH wholesalers in the Finnish district heating market. In this research work, the value for DH selling price is 35 €/MWh [34]. When the value rises, the profit will gradually increase. Furthermore, there might be chance to purchase electricity from the Nordic electricity market. In contrary, DH system is particularly dependent inside the country with characteristic of local market strategy.

5 Discussion

The proposed model of the power plant is simulated in Prosim 5.6 for different design cases by varying the fuel mix and DH load. The different design cases will analyze the feasibility of oxyfuel combustion, flue gas recirculation, district heating, O_2 storage and carbon capture for the proposed power plant. The state of art technology suggests the feasibility of oxyfuel combustion with carbon capture, but there is no explanation of reducing the energy consumption of ASU and a provision to use the waste heat.

Keeping the background problem in mind, this research work has focused on available state of art technologies related to carbon capture along with the incorporation of different variables that may be beneficial for efficiency and economic justification.

Oxyfuel combustion along with flue gas recirculation is an important issue related to carbon capture. For the oxyfuel combustion, it is necessary to separate pure O_2 from air in a highly inefficient air separation unit. In the analysis, a special attention is given to address the high-energy consumption problem of ASU. The design of suitable burners for oxyfuel combustion is an important matter that needs to be developed more in the future for commercial use. All the plants are still in demonstration stage. The portion of flue gas recirculation is 70 %, as many research projects have used this value in a better way. Although it is also possible to optimize that amount, but it seems to be quite difficult with the present scope of this thesis work. Therefore, a standard value of 70% for the flue gas recirculation amount has been taken after proper literature review.

The district heating concept is one of the key features in this thesis. From economic and efficiency perspective, it is a good impression to use the waste heat from the power plant into district heating system. Relevant curves and data are developed to justify the use of CHP plant for the proposed design. Furthermore, the results show a good commercial justification for the increase in district heating load by compromising on electrical power. There is an interesting phenomenon be considered that increase in biomass in co-firing results in a rise in net efficiency.

Due to highly inefficient ASU unit, a promising concept of O_2 storage is developed through this research work. The operational strategy of O_2 storage is linked with the grid electricity price. The feasibility of this concept is clearly explained in the thesis by proper scientific calculation and curves. The data for this analysis is taken from Statistics Finland and Finnish energy market for the year 2011. Therefore, the idea of O_2 storage is well explained with real data and can be used for actual implementations.

A total investigation has been done on the whole process to integrate and properly optimize the proposed design in a scientific way with commercial justification.

6 Conclusion

In the upcoming years, coal will be a dominant source of energy. Although renewable energy technologies will play an important role to meet the energy demand by environmental friendly methods. However, renewable energy is still facing problems for complete commercialization due to financial and technological constraints. These issues will bring opportunities forward to develop a research field to generate clean energy from coal by CCS.

In this thesis, process modeling and optimization have been executed for a co-firing CHP power plant with a facility of carbon capture. The model of the proposed power plant has been created in Prosim 5.6 with the help of suitable tools. For the optimization part, a separate code with statements has written in GAMS programme based on Prosim model. After creating the model, a set of variables have been selected to define the optimization results. The variables are as follows:

(a) Co-firing of coal with biomass
(b) 70% recirculation of flue gas
(c) District heating
(d) O_2 storage concept linked with grid electricity price
(e) Carbon capture and storage.

The proposed model in Prosim 5.6 and its corresponding optimization routine in GAMS model provide us a number of important conclusions that are worth noting and listed as follows:

- There is a linear co-relation between the biomass percentage in co-firing and the net efficiency. The results show a 4-5 % increase in net efficiency with the rise of biomass percentage from 5% to 15 % in co-firing. Therefore, this result justifies the co-firing of coal with biomass concerning net efficiency.

- There is another important conclusion to be considered that the effect of biomass percentage on oxygen requirement of boiler. With the rise of biomass percentage in co-firing from 0 to 15%, the oxygen requirement of the boiler reduces from 83 kg/s to 75 kg/s, because carbon content is less in biomass than coal and decreasing the coal amount (from 100% to 85%) leads the less requirement of O_2 from ASU. Actually, this incident will reduce the power consumption of ASU, which is good for the overall efficiency of a power plant. Therefore, it can be concluded in this context that an increase in overall efficiency of plant can be possible with increase of biomass percentage.

- The concept of O_2 storage introduced in the work will drastically increase the economic efficiency of ASU. The main challenge for oxyfuel combustion is the high power consumption of ASU. If the consumption is reduced then the results and analysis are very relevant and important to the research field of carbon capture. Furthermore, using cheap grid electricity for O_2 separation and stored O_2 for usage during high grid electricity price makes sense for the economy of ASU operation.

- An analysis of heat and power ratio for the CHP plant indicates positive effect during high district heating price. In this thesis, a feasibility analysis with suitable graphs has been conducted to link the variation of heat and power ratio with the grid electricity and district heating price.

By combining the above variables, different design conditions are created in GAMS model for the optimization of the proposed power plant. The design cases reflect the optimized operational scenario that might be very useful for a real power plant. The results will provide a solution for a power plant to modify and optimize their power plant towards the goal of sustainability.

In future, fossil fuel price will be increased. More carbon tax will be imposed as well. As a result, many power generation companies will switch to renewable energy sources. Moreover, they will also focus on increasing efficiency in existing conventional power plants. Biomass based oxyfuel combustion and carbon capture system is one of the best options for reducing greenhouse gases. It will help not only in cutting the amount of CO_2 but in also emphasizing the renewable energy sources for better environment. The implementation of carbon capture technologies in coal-based power plant has significant contribution on GHG emission all over the world. The main driver of biomass based oxyfuel combustion technology is zero emissions CO_2 and near zero for pollutant including NO_x, SO_x and particulates.

6.1 Future work

It has been explained that coal will dominate the fuel trend to be used for power generation next couple of decades. Consistent supply, relatively cheap price and availability in most parts of the world have enabled this fossil fuel to take a lead. No doubt, carbon capture and storage will be a leading contributor for reduction of CO_2 emissions. Moreover, oxyfuel combustion with CCS has the chance to be an attractive technology for the declination of greenhouse gases.

Through this thesis, it has been tried to incorporate together some approaches, such as fuel flexibility by blending coal and biomass, CHP plant for cogeneration concept, using CFB boiler in oxyfuel combustion, CCS system and finally O_2 storage system. These approaches mentioned before have different characteristic with merits and demerits as well. Many researchers and organizations are working collaboratively in this field. All the plants are still in pilot project and demonstration mode. In near future, we will observe the significant development in this CO_2 mitigation field. During this thesis with modeling of the proposed plant, some features came forward to be considered in the future. These several features are mentioned as follows:

- ASU and CPU consume large percentage of the gross power thus decreasing overall efficiency. More research works is essential for a more efficient system.

- The combustion characteristic inside the boiler is an important issue. High pure O_2 with RFG (CO_2-H_2O) has complex characteristics, as combustion atmosphere is quite different in oxyfuel combustion in comparison to conventional power plant. The characteristics like ignition temperature, heat transfer, pollution formation needs more experimental works for better performance.

- Blend of biomass with coal and their combustion behavior and ash properties requires more investigation.

- Effect of higher flame temperature and different combustion situations may affect the boiler life. These issues require more evaluation.

- As the O_2 storage system in oxyfuel combustion and CCS is relatively new, intensive research work is essential for optimization of storage system and pricing of electricity and DH.

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APPENDICES

APPENDIX A: Ongoing and proposed oxyfuel combustion projects [8]

Project name	Leader	Location	Scale	Technology	MWe	New /Retrofit	Power Gen	CO_2 Seq	Start-up
Jupiter Pearl Plant	Jupiter	USA	Pilot		22(MW_{th})	Retrofit	No	NA	2007
B&W pilot plant	B&W	USA	Pilot	PCa	30(MW_{th})	Retrofit	No	N	2008
OxyCoal-UK	Doosan Babcock	UK	Pilot	PCa	40(MW_{th})	Retrofit	No	N	2009
Alstom Windsor Facility	Alstom	USA	Pilot	PCa	15(MW_{th})	Retrofit	No	N	2009
Schwarze Pumpe	Vattenfall	Germany	Pilot	PCa	10	New	No	Seqd	2008
Callide-A	CS Energy, IHI etc.	Australia	Pilot	PCa	30	Retrofit	Yes	Seqd	2011
Compostilla (OXY-CFB-300) Phase I	ENDESA, CIUDEN and Foster Wheeler	Spain	Pilot	CFBb	17	New	Yes	Seqd	2011–2012
Jamestown	Jamestown BPU	USA	Demo	CFB	43	New	No	Seqd	2013
Janschwalde	Vattenfall	Germany	Demo	PCa	250	New	Yes	Seqd	2015
FutureGen	FutureGen Alliance	USA	Demo	PCa	200	Retrofit	Yes	Seqd	2015
Compostilla (OXY-CFB-300) Phase II	ENDESA, CIUDEN and Foster Wheeler	Spain	Demo	CFBb	300	New	Yes	Seqd	2015
Youngdong	KEPCO	S. Korea	Demo	PCa	100	Retrofit	Yes	Seqd	2016
Black Hills Power	Black Hills Corporation	USA	Demo	PCa	100	New	Yes	NAc	2016

APPENDIX B: Simulation results for all design cases

Design Case 1: (Fuel mix 1 & DH 90%)

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.93	1829.75	1796.19	1761.38
Flue gas mass flow for capture	kg/s	106.62	103.09	99.95	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.17
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.01
SO_2		0.45	0.44	0.43	0.42
Steam flow for 100% DH Load	kg/s	280.00	280.00	280.00	280.00
DH load	MW	589.16	590.26	590.06	593.33
Gross power	MW	311.01	296.47	283.32	266.15
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	197.28	186.58	177.09	163.96
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.19	0.19	0.18	0.18
Net efficiency (DH & net power)		0.76	0.78	0.80	0.82
Power to heat ratio		0.33	0.32	0.30	0.28
DH Temperature	°C	100	100	100	100
Parameter	**Unit**	**Fuel mix 1**	**Fuel mix 2**	**Fuel mix 3**	**Fuel mix 4**
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.87	1829.69	1796.12	1761.32
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.17
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 90% DH Load	kg/s	252.00	252.00	252.00	252.00
DH load	MW	530.28	531.26	531.08	534.06
Gross Power	MW	318.36	304.15	291.31	274.43
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	204.63	194.26	185.08	172.24
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.19	0.19	0.19
Net efficiency (DH & net power)		0.71	0.72	0.74	0.76
Power to heat ratio		0.39	0.37	0.35	0.32
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.81	1829.62	1796.07	1761.25
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.17
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 80% DH Load	kg/s	224.00	224.00	224.00	224.00
DH load	MW	471.40	472.25	472.10	474.78
Gross power	MW	325.22	311.31	298.72	282.13
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	211.49	201.42	192.49	179.94
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.20	0.20	0.19
Net efficiency (DH & net power)		0.66	0.67	0.69	0.71
Power to heat ratio		0.45	0.43	0.41	0.38
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.76	1829.57	1796.01	1761.19
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.17
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 70% DH Load	kg/s	196.00	196.00	196.00	196.00
DH load	MW	412.50	413.24	413.13	415.48
Gross power	MW	331.56	317.95	305.59	289.33
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	217.83	208.06	199.36	187.14
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.21	0.21	0.21	0.20
Net efficiency (DH & net power)		0.61	0.62	0.64	0.65
Power to heat ratio		0.53	0.50	0.48	0.45
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.71	1829.52	1795.95	1761.14
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.17
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 60% DH Load	kg/s	168.00	168.00	168.00	168.00
DH load	MW	353.60	354.22	354.15	356.17
Gross power	MW	337.37	324.07	311.94	296.00
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	223.64	214.18	205.71	193.81
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.22	0.21	0.21	0.21
Net efficiency (DH & net power)		0.56	0.57	0.58	0.59
Power to heat ratio		0.63	0.60	0.58	0.54
DH Temperature	°C	100	100	100	100

Design case 2:
(Fuel mix 4 & DH 90%)

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.55	1830.28	1796.59	1761.51
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 100% DH Load	kg/s	280	280	280	280
DH load	MW	584.59	587.23	587.85	588.42
Gross power	MW	308.80	293.12	279.68	266.12
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	195.07	183.23	173.45	163.93
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.19	0.18	0.18	0.18
Net efficiency (DH & net power)		0.75	0.77	0.79	0.81
Power to heat ratio		0.33	0.31	0.30	0.28
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.50	1830.22	1796.53	1761.44
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 90% DH Load	kg/s	252.00	252.00	252.00	252.00
DH load	MW	526.60	528.96	529.54	530.06
Gross power	MW	314.75	299.62	286.74	273.71
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	201.02	189.73	180.51	171.52
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.19	0.19	0.19	0.19
Net efficiency (DH & net power)		0.70	0.72	0.74	0.76
Power to heat ratio		0.38	0.36	0.34	0.32
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.46	1830.17	1796.47	1761.38
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 80% DH Load	kg/s	224.00	224.00	224.00	224.00
DH load	MW	468.51	470.59	471.15	471.61
Gross power	MW	319.67	305.12	292.71	280.19
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	205.94	195.23	186.48	178.00
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.19	0.19	0.19
Net efficiency (DH & net power)		0.65	0.66	0.68	0.70
Power to heat ratio		0.44	0.41	0.40	0.38
DH Temperature	°C	100	100	100	100
Parameter	**Unit**	**Fuel mix 1**	**Fuel mix 2**	**Fuel mix 3**	**Fuel mix 4**
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.42	1830.14	1796.43	1761.33
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 70% DH Load	kg/s	196.00	196.00	196.00	196.00
DH load	MW	410.31	412.13	412.64	413.05
Gross power	MW	323.52	309.53	297.64	285.66
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	209.79	199.64	191.41	183.47
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.20	0.20	0.20
Net efficiency (DH & net power)		0.60	0.61	0.63	0.64
Power to heat ratio		0.51	0.48	0.46	0.44
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.39	1830.11	1796.40	1761.30
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 60% DH Load	kg/s	168.00	168.00	168.00	168.00
DH load	MW	352.01	353.57	354.02	354.38
Gross power	MW	326.24	312.82	301.48	290.04
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	212.51	202.93	195.25	187.85
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.20	0.20	0.20
Net efficiency (DH & net power)		0.54	0.56	0.57	0.59
Power to heat ratio		0.60	0.57	0.55	0.53
DH Temperature	°C	100	100	100	100

Design case 3: (Fuel mix 1 & DH 70%)					
Parameter	**Unit**	**Fuel mix 1**	**Fuel mix 2**	**Fuel mix 3**	**Fuel mix 4**
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.91	1829.73	1796.17	1761.35
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 100% DH Load	kg/s	280	280	280	280
DH load	MW	586.48	587.56	587.34	590.32
Gross power	MW	311.64	296.96	283.71	266.73
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	197.91	187.07	177.48	164.54
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.19	0.19	0.18	0.18
Net efficiency (DH & net power)		0.75	0.77	0.79	0.82
Power to heat ratio		0.34	0.32	0.30	0.28
DH Temperature	°C	100	100	100	100
Parameter	**Unit**	**Fuel mix 1**	**Fuel mix 2**	**Fuel mix 3**	**Fuel mix 4**
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.83	1829.66	1796.09	1761.28
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 90% DH Load	kg/s	252.00	252.00	252.00	252.00
DH load	MW	528.44	529.43	529.23	531.96
Gross power	MW	319.29	304.77	291.74	274.95
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	205.56	194.88	185.51	172.76
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.19	0.19	0.19
Net efficiency (DH & net power)		0.71	0.72	0.74	0.76
Power to heat ratio		0.39	0.37	0.35	0.32
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.77	1829.58	1796.02	1761.21
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 80% DH Load	kg/s	224.00	224.00	224.00	224.00
DH load	MW	470.28	471.56	470.98	473.45
Gross power	MW	326.67	312.34	299.46	282.85
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	212.94	202.45	193.23	180.66
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.20	0.20	0.20
Net efficiency (DH & net electricity)		0.66	0.67	0.69	0.71
Power to heat ratio		0.45	0.43	0.41	0.38
DH Temperature	°C	100	100	100	100
Parameter	**Unit**	**Fuel mix 1**	**Fuel mix 2**	**Fuel mix 3**	**Fuel mix 4**
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.70	1829.51	1795.95	1761.13
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 70% DH Load	kg/s	196.00	196.00	196.00	196.00
DH load	MW	411.98	412.75	412.62	414.79
Gross power	MW	333.82	319.66	306.9	290.5
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	220.09	209.77	200.67	188.31
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.21	0.21	0.21	0.20
Net efficiency (DH & net power)		0.61	0.62	0.64	0.65
Power to heat ratio		0.53	0.51	0.49	0.45
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1861.64	1829.45	1795.89	1761.06
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 60% DH Load	kg/s	168.00	168.00	168.00	168.00
DH load	MW	353.56	354.21	354.10	355.99
Gross Power	MW	340.66	326.72	314.12	297.90
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	226.93	216.83	207.89	195.71
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.22	0.22	0.22	0.21
Net efficiency (DH & net power)		0.56	0.57	0.58	0.60
Power to heat ratio		0.64	0.61	0.59	0.55
DH Temperature	°C	100	100	100	100

Design case 4:
(Fuel mix 4 & DH 70%)

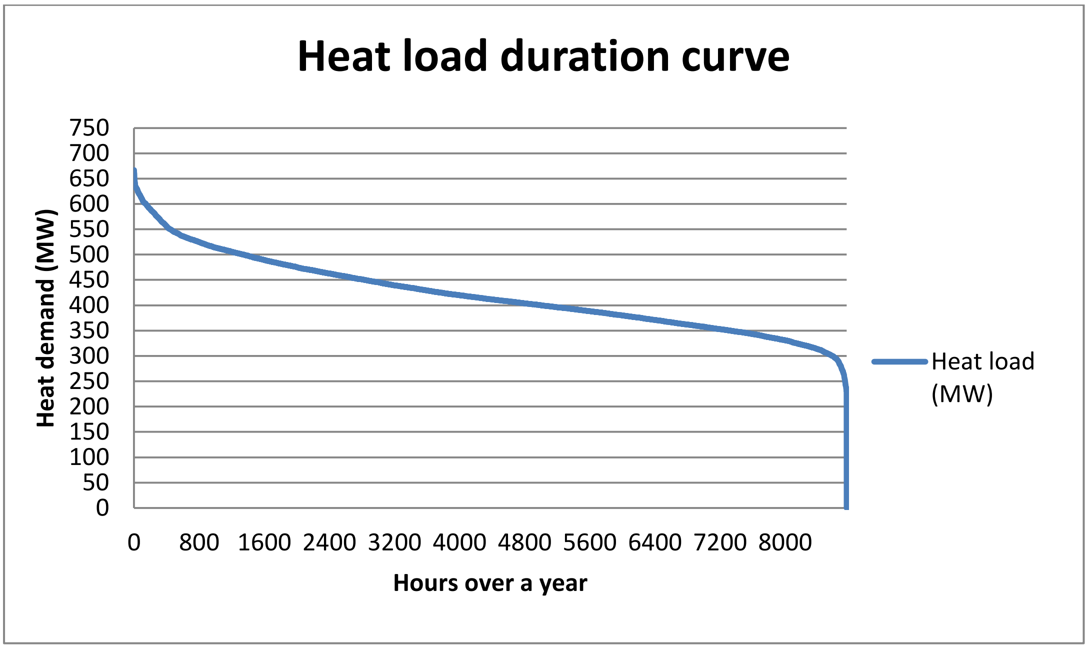
Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.69	1830.42	1796.73	1761.40
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 100% DH Load	kg/s	280	280	280	280
DH load	MW	583.13	585.81	586.36	587.05
Gross power	MW	310.04	293.84	280.20	265.63
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	196.31	183.95	173.97	163.44
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.19	0.18	0.18	0.18
Net efficiency (DH & net power)		0.75	0.77	0.79	0.81
Power to heat ratio		0.34	0.31	0.30	0.28
DH Temperature	°C	100	100	100	100
Parameter	**Unit**	**Fuel mix 1**	**Fuel mix 2**	**Fuel mix 3**	**Fuel mix 4**
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.63	1830.36	1796.66	1761.58
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 90% DH Load	kg/s	252.00	252.00	252.00	252.00
DH load	MW	525.41	527.80	528.33	528.83
Gross power	MW	317.24	301.36	287.97	274.47
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	203.51	191.47	181.74	172.28
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.19	0.19	0.19
Net efficiency (DH & net power)		0.70	0.72	0.74	0.76
Power to heat ratio		0.39	0.36	0.34	0.33
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.57	1830.29	1796.59	1761.51
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 80% DH Load	kg/s	224.00	224.00	224.00	224.00
DH load	MW	467.56	469.66	470.16	470.61
Gross power	MW	324.10	308.51	295.31	282.04
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	210.37	198.62	189.08	179.85
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.20	0.20	0.20	0.19
Net efficiency (DH & net power)		0.65	0.67	0.68	0.70
Power to heat ratio		0.45	0.42	0.40	0.38
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.51	1830.23	1796.53	1761.44
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 70% DH Load	kg/s	196.00	196.00	196.00	196.00
DH load	MW	409.58	411.41	411.87	412.27
Gross power	MW	330.59	315.29	302.28	289.25
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	216.86	205.40	196.05	187.06
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.21	0.21	0.20	0.20
Net efficiency (DH & net power)		0.60	0.62	0.63	0.65
Power to heat ratio		0.53	0.50	0.48	0.45
DH Temperature	°C	100	100	100	100

Parameter	Unit	Fuel mix 1	Fuel mix 2	Fuel mix 3	Fuel mix 4
Fuel flow					
Coal	kg/s	40	38	36	34
Biomass	kg/s	0	2	4	6
Oxygen mass flow	kg/s	83.65	80.76	77.88	75.00
Flue gas mass flow	kg/s	413.48	404.03	394.57	385.11
Flue gas temperature inlet to Boiler	°C	1862.46	1830.18	1796.47	1761.38
Flue gas mass flow for capture	kg/s	106.62	103.09	99.55	96.01
Gas analysis (%)					
N_2		6.10	6.09	6.08	6.07
H_2O		3.17	3.17	3.17	3.07
CO_2		87.23	87.25	87.27	87.29
O_2		3.02	3.01	3.01	3.00
SO_2		0.45	0.44	0.43	0.42
Steam flow for 60% DH Load	kg/s	168.00	168.00	168.00	168.00
DH load	MW	351.47	353.04	353.45	353.80
Gross power	MW	336.70	321.68	308.86	296.05
ASU	MW	63.84	61.64	59.44	57.24
CPU	MW	49.89	48.25	46.79	44.95
Net power	MW	222.97	211.79	202.63	193.86
Fuel power	MW	1039.32	1001.52	963.72	925.92
Electrical efficiency		0.21	0.21	0.21	0.21
Net efficiency (DH & net power)		0.55	0.56	0.58	0.59
Power to heat ratio		0.63	0.60	0.57	0.55
DH Temperature	°C	100	100	100	100

APPENDIX C: Heat load duration curve [31]



APPENDIX D: Elspot price for 2011 in Finland [35]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Series1	68.92	64.58	60.91	52.93	54.42	48.54	42.20	48.98	38.86	36.90	42.03	33.34