

LAPPEENRANTA UNIVERISTY OF TECHNOLOGY
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**PROMOTING GROWTH IN THE USE OF BIOENERGY IN EUROPE BY
CONVERTING EXISTING COAL-FIRED POWER PLANTS TO BIOMASS**

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Supervisor: Professor Esa Vakkilainen, D.Sc.

ABSTRACT

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Repowering existing power plants by replacing coal with biomass might offer an interesting option to ease the transition from fossil fuels to renewable energy sources and promote a further expansion of bioenergy in Europe, on account of the potential to decrease greenhouse gas emissions, as well as other pollutants (SO_x, NO_x, etcetera). In addition, a great part of the appeal of repowering projects comes from the opportunity to reuse the vast existing investment and infrastructure associated with coal-based power generation. Even so, only a limited number of experiences with repowering are found. Therefore, efforts are required to produce technical and scientific evidence to determine whether said technology might be considered feasible for its adoption within European conditions. A detailed evaluation of the technical and economic aspects of this technology constitutes a powerful tool for decision makers to define the energy future for Europe. To better illustrate this concept, a case study is analyzed. A Slovakian pulverized coal plant was used as the basis for determining the effects on performance, operation, maintenance and cost when fuel is shifted to biomass. It was found that biomass fuel properties play a crucial role in plant repowering. Furthermore, results demonstrate that this technology offers renewable energy with low pollutant emissions at the cost of reduced capacity, relatively high levelized cost of electricity and sometimes, a maintenance-intensive operation. Lastly, regardless of the fact that existing equipment can be reutilized for the most part, extensive additions/modifications may be required to ensure a safe operation and an acceptable performance.

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TABLE OF CONTENTS

ABSTRACT	2
ACKNOWLEDGEMENTS.....	3
LIST OF ABBREVIATIONS AND SYMBOLS.....	7
1. INTRODUCTION.....	9
2. BIOMASS AND BIOENERGY	10
2.1 Current Status of Bioenergy in Europe	12
2.1.1 Demand and Supply.....	13
2.1.2 Imports.....	14
2.2 Biomass Conversion Technologies	15
2.2.1 Combustion.....	16
2.2.2 Gasification	17
2.2.3 Pyrolysis	17
2.2.4 Liquefaction.....	17
3. POWER GENERATION TECHNOLOGY	18
3.1. Biomass Combustion	19
3.2. Pulverized Fuel Combustion (PFC)	20
3.3. Stoker Firing.....	22
3.4. Fluidized Bed Combustion (FBC)	23
4. PFC TO BIOMASS FIRING CONVERSION	26
5. STATE OF THE ART	28
5.1 Biomass Characteristics and their Interaction with Combustion Systems	28
5.1.1 Moisture Content.....	28
5.1.2 Calorific Value.....	28
5.1.3 Particles Dimensions and Bulk Density	29
5.1.4 Presence of Carbon, Hydrogen, Oxygen and Volatiles.....	29

5.1.5	Presence of Nitrogen, Sulfur and Chlorine	29
5.1.6	Ash Content	30
5.2	Considerations for Full-Biomass Power Plant Conversion	31
5.2.1	Fuel Preparation, Storage and Delivery.....	31
5.2.2	Size Reduction.....	32
5.2.3	Performance and Integrity of the Boiler	33
5.2.4	Pollutant Emissions.....	34
5.2.5	Ash Utilization	35
5.3	State-of-the-art Fuels	35
5.3.1	Wood Chips	36
5.3.2	Wood Pellets.....	37
5.3.3	Torrefied Pellets.....	37
5.3.4	Steam Explosion Pellets.....	37
5.4	Case Studies.....	38
5.4.1	Atikokan Generating Station.....	38
5.4.2	Tilbury B Power Station.....	40
5.5	Coal-Based Power Generation in Europe.....	42
6.	EVALUATION OF TECHNICAL FEASIBILITY.....	46
6.1	Study Unit Description.....	47
6.2	Biomass Feedstock Selection	49
6.3.	Initial Considerations for the Full Conversion of Unit 1 to Biomass	49
6.4.	Results.....	50
6.5.	Discussion.....	53
6.6.	Proposed Modifications for Vojany I Unit 1	58
6.6.1.	Delivery and reception	59
6.6.2.	Biomass handling.....	59
6.6.3.	Storage	60

6.6.4. Fuel preprocessing.....	60
6.6.5. Burners	61
7. EVALUATION OF ECONOMIC FEASIBILITY	63
7.1. Key Assumptions	64
7.2. Results for LCOE	65
7.3. Additional considerations	68
8. CONCLUSIONS.....	69
9. BIBLIOGRAPHY	70
APPENDICES	76

LIST OF ABBREVIATIONS AND SYMBOLS

A	Heat Transfer Area
a.r	As Received
CER	Certified Emission Reduction
CHP	Combined Heat and Power
C _p	Specific Heat
D	Diameter
DAF	Dry Ash Free
EU	European Union
EUR	Euro
FB	Fluidized Bed
FEGT	Furnace Exit Gas Temperature
GHG	Green House Gases
GJ	Gigajoule
HHV	Higher Heating Value
k	Thermal conductivity
LCOE	Levelized Cost of Electricity
LHV	Lower Heating Value
LMTD	Log Mean Temperature Difference
LMTD	Log Mean Temperature Difference
MJ	Megajoule
MPa	Megapascal
MSW	Municipal Solid Waste
Mtoe	Million Tonnes of Oil Equivalent
MWe	Megawatts of electricity
MWh	Megawatt hour
NG	Natural Gas
NREAP	National Renewable Energy Action Plan
Nu	Nusselt Number
O&M	Operation and Maintenance
OD	External Diameter
PFC	Pulverized Fuel Combustion

Pr	Prandtl Number
Q	Heat Load
RES	Renewable Energy Sources
Rn	Reynolds Number
SCR	Selective Catalytic Reduction
sLCOE	Simplified Levelized Cost of Electricity
SNCR	Selective Non-Catalytic Reduction
tCO _{2e}	Ton of CO ₂ Equivalent
THK	Thickness
U	Global Heat Transfer Coefficient
w.b	Wet Basis
wt	Weight
λ	Heat Transfer Coefficient

1. INTRODUCTION

Since the dawn of civilization, biomass has been used in the form of residues, firewood and charcoal for cooking, metalworking, brickmaking and heating. This trend continues even today, especially in developing countries. In fact, many researchers around the globe have acknowledged the benefits of biomass combustion and built modern biomass-powered facilities to provide electricity and heating in a more efficient way. Consequently, modern applications are rapidly displacing traditional utilization of biomass in developed nations. These technologies demand capital, market structure and a high level of expertise. It is still unclear how long it will take for modern technologies to replace traditional uses of biomass, or what technologies will prevail. In some cases, factors unrelated to energy can play a crucial role. What is evident is the long road ahead as a result of the difference in the level of commitment to protection of the human habitat and the environment.

This work will focus its efforts on studying the effects of the direct combustion of biomass using facilities originally designed to burn coal as a promising process that may ease the transition from fossil fuels to RES and promote a further expansion of bioenergy in Europe. Presently, only a limited number of experiences in this field have taken place, justifying the necessity of this work which aims to clarify the uncertainties surrounding this technology and to provide technical and scientific evidence to determine whether said technology might be considered feasible for its adoption within European conditions.

In order to appreciate the technical and scientific intricacies of repurposing a coal-fired power plant, it is necessary to develop a clear understanding of the importance of biomass in modern times and its implications for the future energy perspective of the EU. Firstly, current trends in this field will be reviewed and subsequently, a model will be developed to estimate the resulting technical parameters of a coal-fired power plant running on biomass. Then, based on the results provided by the model and on the information gathered from case studies, it will be discussed how biomass combustion might alter a plant's operations and maintenance (O&M) and how power generation facilities can be modified accordingly. Furthermore, a critical factor determining the feasibility of an emerging technology is the cost factor, making the inclusion of an economic estimation necessary. After that, recommendations are made for the application and further development of this technology. Finally, conclusions are drawn.

2. BIOMASS AND BIOENERGY

The utilization of an energy resource readily available in all kinds of forms and qualities, such as biomass, has allowed mankind to move forward by covering most of their most basic needs, including food, heating, fuel and fibers. Even today, biomass continues to play a key role in modern society as one of the most important sources of renewable energy. Biomass can provide energy input for heat and electricity generation, and fuel for transportation. In addition, biomass can be defined as all kinds of materials directly or indirectly derived from photosynthesis reactions, including wood and wood-derived fuels, fuel crops, agricultural and agro-industrial by-products, and animal by-products (Van Loo & Koppejan, 2008). The term *bioenergy* comprises all sorts of energy derived from biomass. Table 1 illustrates the different classifications of biomass and their typical forms of usage.

Table 1. Biomass Classification (Rosillo-Calle, et al., 2007)

<i>Production side, supply</i>	<i>Common groups</i>	<i>Users side, demand examples</i>
Direct woodfuels	WOODFUELS	Solid: fuelwood (wood in the rough, chips, sawdust, pellets), charcoal
Indirect woodfuels		Liquid: black liquor, methanol, pyrolytic oil
Recovered woodfuels		Gases: products from gasification and pyrolysis gases of above fuels
Wood-derived fuels		
Fuel crops	AGROFUELS	Solid: straw, stalks, husks, bagasse, charcoal from the above biofuels
Agricultural by-products		Liquid: ethanol, raw vegetable oil, oil diester, methanol, pyrolytic oil
Animal by-products		Gases: biogas, producer gas, pyrolysis gases from agrofuels
Agro-industrial by-products		
	MUNICIPAL BY-PRODUCTS	Solid: municipal solid waste (MSW)
Municipal by-products		Liquid: sewage sludge, pyrolytic oil from MSW
		Gases: landfill gas, sludge gas

Characterized by its abundance and potential to be a sustainable source of energy, the world has become more interested in biomass in recent times. Some of the benefits offered by bioenergy are the reduction potential for greenhouse gas (GHG) emissions, displacement of non-renewable fuels, improvement of living standards and the prospect of becoming a major source of employment.

Since the dawn of civilization, biomass has been used in the form of residues, firewood and charcoal for various purposes such as cooking, metalworking, brickmaking and heating. This trend continues today, especially in developing countries. The traditional uses of biomass are often very inefficient, meaning that only a small fraction of the energy contained in the fuel is actually transformed into usable energy. Furthermore, traditional use of biomass is also associated with negative impacts on both human health and the environment. Still, traditional utilization of biomass accounts for 35% of the present energy needs of three quarters of the world's population (Rosillo-Calle, et al., 2007). In contrast, many around the globe have recognized the benefits of biomass and have developed technologies to provide electricity and heating in a more safe and efficient form. Modern applications are rapidly displacing the traditional utilization of biomass in developed nations. These technologies may demand important investments, a mature market structure and a high level of expertise.

Many experts agree that bioenergy could satisfy the world energy demand by an ample margin (El Basam, 2010). It is estimated that bioenergy has the potential to generate 400 EJ per year during this century, compared to the present use of fossil fuels of roughly 388 EJ (ibid). However, in order to cover a significant part of the energy demand with biomass, appropriate technology and processes need to be introduced. Currently, biomass covers approximately 10% of the world energy demand (VTT, 2009). The present and future reliance on biomass as an energy source makes necessary the development of more affordable, cleaner and more efficient technologies.

In order to utilize biomass as an energy input, it has to be subjected to conversion processes to produce usable energy. These processes can be either biochemical or thermochemical and their selection is determined by both the physical and the chemical characteristics of the biomass.

2.1 Current Status of Bioenergy in Europe

The scientific community agrees that measures must be taken to moderate the effects of global warming (NASA, 2014). Developed nations have taken the first step with the creation of binding agreements that enforce the reduction of GHG emissions in order to contain the rise in global temperature to within 2 °C (European Commission, 2015a). Playing an active role in this world-wide effort, the EU has set a target for gross final energy consumption derived from renewable sources of 20% by 2020 and 34% by 2030 (European Commission, 2015b). Final energy includes electricity, heating, cooling and transportation.

Boosting the utilization of renewable energy sources (RES) is an ambitious plan and it requires much more than setting a goal. For this reason, the establishment of a binding agreement for the EU is accompanied by a series of support mechanisms, such as a legal framework for promoting renewable electricity, the establishment of clear pathways for the development of RES, cooperation programs to reach the targets in a cost-effective manner and the definition of sustainability criteria. Member states of the EU are free to choose the support mechanism that is most convenient to the purpose of achieving their target. Nevertheless, such targets are different for each member as a result of their different RES potentials and particular energy mix. (EURELECTRIC, 2011)

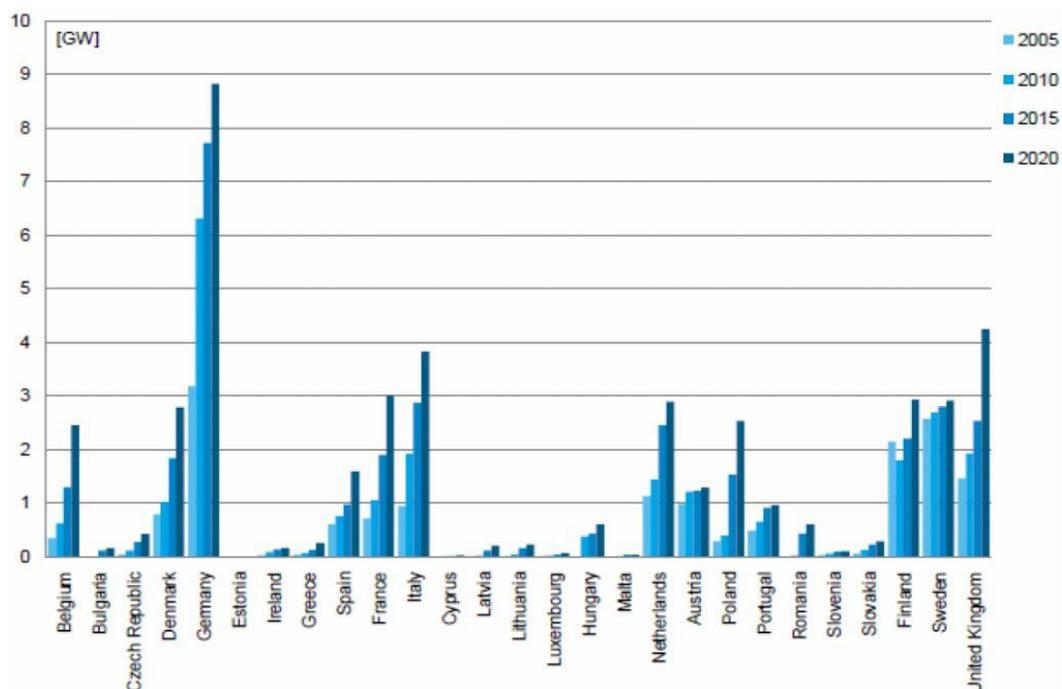


Figure 1. Existing and future biomass electricity production capacity (EURELECTRIC, 2011)

The gradual transition to energy systems based on RES presents a challenge for the traditionally fossil fuel-based economies of the EU. As shown on Figure 1, Germany possesses the largest biomass-based installed capacity within the EU, followed by the United Kingdom and Italy. Also, it is of notice that in the case of countries like Belgium and Poland, significant efforts are required to increase the share of RES to the stipulated levels. This pattern is also followed by Denmark, France and many others. On the other hand, members such as Sweden, Austria and Finland are close to reaching the commitment's goals. In addition, it is considered that the expansion in generation capacity will not be always consistent with expansion in electricity production as a result of the difficulty to increase the average load factor of bioenergy technology. (ibid)

2.1.1 Demand and Supply

As a mechanism to report the roadmap to reach the RES targets, every member state of the EU submitted a national renewable energy action plan (NREAP) to the European Commission in 2010. These reports offer an overview of the current status of bioenergy and projections of future use of biomass. Figure 2 shows estimates of electricity generation from biomass across the EU member states. Germany stands out for its considerable growth in this sector, followed by the UK, Italy, Belgium, France, the Netherlands and Poland.

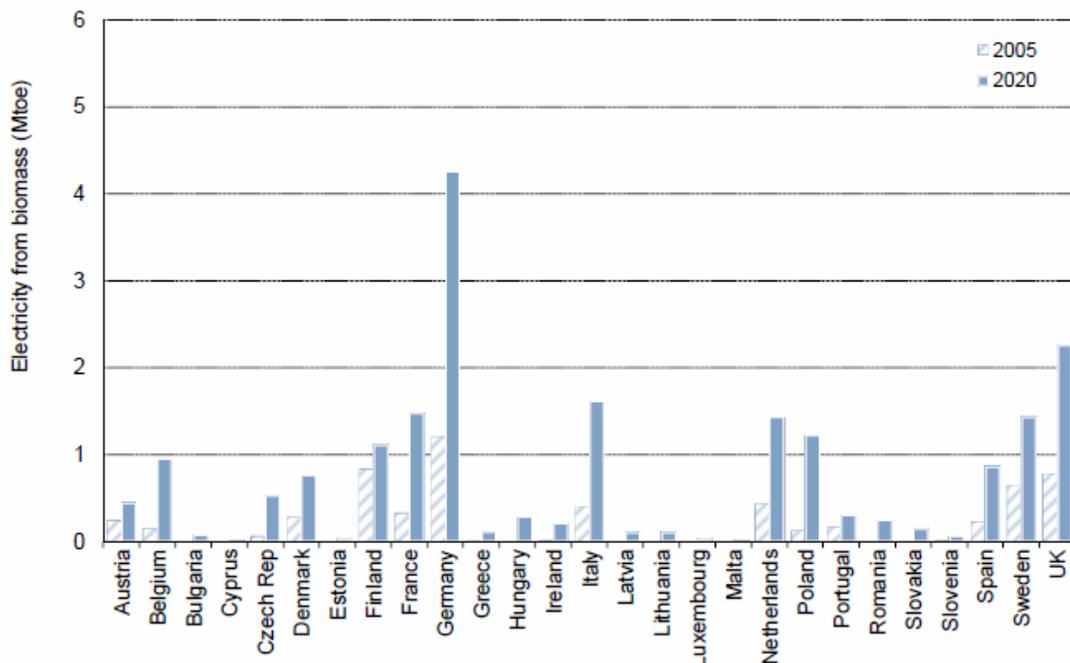


Figure 2. Electricity from biomass in 2005 and 2020 according to the NREAPs (EURELECTRIC, 2011)

In a study carried by the energy consulting firm PÖYRY in 2011, it was stated that NREAPs show rather optimistic projections for the future use of biomass and that additional efforts are needed to close the gap between demand and supply of biomass (PÖYRY, 2011). Instead, *ibid* presents more conservative projections. According to their findings, by 2020 the demand for solid biomass for primary energy use will be in the order of 146-158 Mtoe. At the same time, biomass supply is projected to reach 120 Mtoe. Consequently, a gap in supply is to be expected, ranging from 26 to 38 Mtoe.

Biomass from agriculture is predicted to show the highest growth rate, from 13 Mtoe in 2010 to 36 Mtoe in 2020, followed by waste-to-energy sector from 6 Mtoe in 2010 to 14 Mtoe in 2020. In contrast, biomass from the forestry industry is projected to have a mild growth rate, increasing from 64 Mtoe in 2010 to 71 Mtoe in 2020. The present supply of biomass in Europe is approximately 82 Mtoe, with an annual growth rate of 3.3% from 2010 to 2015 and 4.7% from 2015 to 2020. Once more, PÖYRY (2011) declares that this growth rate is insufficient and needs to rise to 5.2%, hence demanding additional investments in the biomass supply chain. Any stalling in the growth of biomass production can lead to a further increase in the supply gap. The development, support and promotion of biomass from agriculture will have a significant impact in the future supply of biomass in the EU.

2.1.2 Imports

At this point, it is clear that in order to close the supply gap, biomass imports are required. Pellets are the main form of solid biomass imported to Europe, coming from distant places such as the USA and Canada and from the vicinity of Russia. As shown on Figure 3, it is estimated that other regions with potential to become reliable sources of biomass are South America, Central-Western Africa and Australia. (EURELECTRIC, 2011)

The biomass required to close the supply gap might be found on global markets. Nevertheless, the structure of the existing supply chains may not be prepared to handle the large volumes of biomass corresponding to 26-38 Mtoe (PÖYRY, 2011). Another concern is the lack of a widely accepted sustainability criteria which could deal effectively with the economic and political situation in different supplying countries (*ibid*). Finally, the eventual apparition of new players in the global biomass market is another reason for concern. Other economies may start promoting their own RES schemes, causing an increase of market prices and putting the reliance on

biomass imports at risk (EURELECTRIC, 2011).

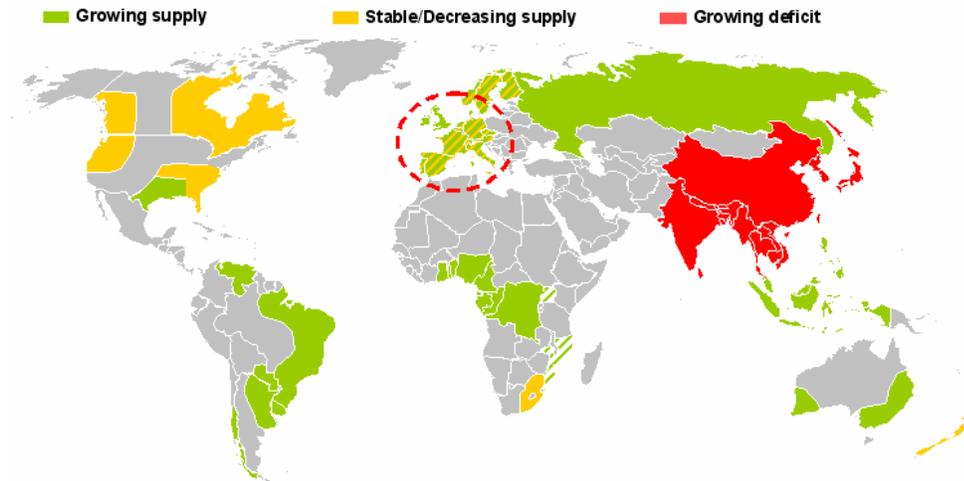


Figure 3. Potential of Biomass Imports (PÖYRY, 2011)

Even with conservative projections, experts agree that sufficient land and waste from both agriculture and forestry industry are available to meet RES targets for 2020, without endangering food supply, threatening virgin forest or competing with the forestry industry (PÖYRY, 2011).

2.2 Biomass Conversion Technologies

To benefit from biomass, it has to be transformed into useful energy (heat or electricity) or energy carriers (charcoal, oil or gas). The two main routes for the transformation of biomass fuels are thermochemical processes and biochemical/biological processes. Each process utilizes dedicated equipment, differs in its operation conditions and delivers different products. The selection of the transformation processes is determined by the characteristics of the biomass, end-user requirements, environmental standards and economic conditions (Pandey, 2009). This study focuses on thermochemical transformation processes, more specifically on direct combustion.

The operation principle of thermochemical transformation processes is the heating of biomass at high temperatures. There are four thermochemical processes used for energy generation: combustion, gasification, pyrolysis and liquefaction. Figure 4 shows the end uses related to different thermochemical transformation technologies. In the next section, these processes will be expanded further.

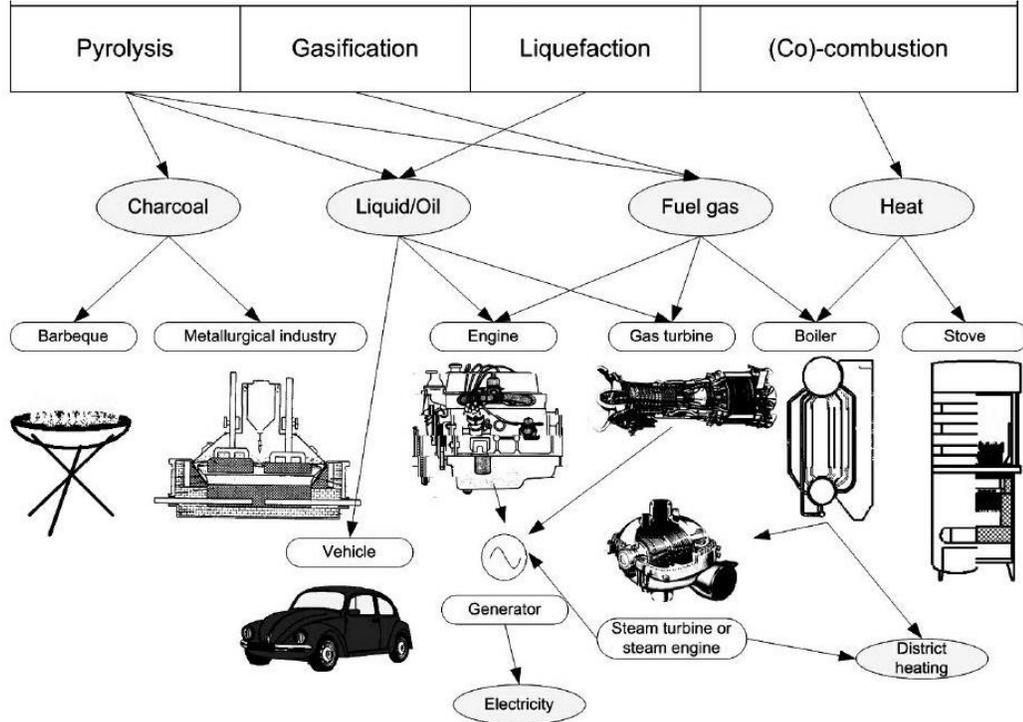


Figure 4. Thermochemical Transformation Technologies (Van Loo & Koppejan, 2008)

2.2.1 Combustion

According to Rosillo-Calle *et al.* (2007), combustion technologies are responsible for approximately 90% of the energy obtained from biomass. This involves the conversion of the chemical energy contained in biomass into more useful forms of energy such as heat, mechanical power or electricity. Furthermore, combustion requires the utilization of different equipment: boilers, furnaces, stoves, steam turbines, generators, etcetera. Also, commercial and industrial combustion plants can burn a wide variety of biomass products, from harvested wood to municipal solid waste.

Combustion can be used for different purposes in both small-scale and large-scale applications. On the one hand, small-scale combustion typically provides energy for cooking, manufacturing and space heating. These applications are characterized by high energy losses and as a result, poor efficiency. On the other hand, large-scale combustion facilities generate electricity with a conversion efficiency in the order of 17 to 25%. Meanwhile, CHP facilities can reach efficiencies of almost 85%, providing that a good use for the residual heat is available (*ibid.*). The main systems for large-scale biomass combustion are stoker firing, fluidized bed combustion (FBC) and pulverized fuel combustion (PFC).

2.2.2 Gasification

Gasification is an endothermic process in which a solid fuel is converted into a combustible gas mixture. It benefits from the high efficiency offered by gas turbines and heat recovery steam generators. Another major advantage of gasification is the potential to replace fossil fuels without major modifications to existing equipment. For example, gasified biomass can displace natural gas (NG) or diesel in industrial boilers and furnaces. Similarly, it can displace gasoline or diesel in internal combustion engines. Gasifiers can make use of a wide range of biomass feedstock, such as rice husks, coconut shells, wood, etcetera. The low heating value gas can be either burnt directly or further processed, to be used as fuel in gas engines or gas turbines. (Pandey, 2009)

2.2.3 Pyrolysis

Pyrolysis is the thermal decomposition of biomass in an inert atmosphere. The resulting products can be either solid, liquid or gaseous, according to process variables such as temperature and residence time (Dahlquist, 2013). Bio-oil is the most common product of pyrolysis, and it offers multiple alternatives for its utilization as liquid fuel or as source of organic chemicals (ibid). In addition, marketable sub products of pyrolysis may offer a source of additional revenue (Pandey, 2009). Cellulose-based biomass has shown the highest yields, at 85-90% wt on dry feed; hence, the majority of the R&D work has been focused on wood biomass (Rosillo-Calle, et al., 2007).

2.2.4 Liquefaction

Liquefaction converts biomass into a marketable liquid product using a catalyst and adding hydrogen to a low-temperature, high-pressure environment (Pandey, 2009). This technology is still in its early stages and additional efforts are needed to achieve both technical and economic feasibility. On the one hand, considerable amounts of oxygen must be removed to obtain fuel fit for utilization (Behrendt, et al., 2008). Furthermore, the end product of liquefaction, heavy oil, often results problematic for traditional fuel handling systems (Pandey, 2009). On the other hand, the additional complexity of liquefaction systems result expensive, compared to pyrolysis and gasification (ibid).

3. POWER GENERATION TECHNOLOGY

Advancement of modern society relies upon abundant, reliable and inexpensive supply of energy (Pritzker, 2014). What is more, energy represents a fundamental aspect of the economic growth and security of Europe. Therefore, power generation technology has been actively developed for the best part of the last two centuries. A power plant is a facility in which takes place the transformation of the chemical energy contained in the fuel (coal, biomass, NG, etcetera) into heat or electricity in the most efficient and economically feasible manner. In these facilities, conversion of water to steam is the predominant technology. In addition, a typical power plant produces usable energy as a result of the interaction of several systems such as fuel reception and preparation, fuel combustion and steam generation, environmental protection, turbine generator, condenser and feedwater system and also heat rejection. The steam generator or boiler is regarded as the central component of a steam power plant (Woodruff, et al., 2004). Figure 5 shows the main systems that comprise a conventional coal-firing power plant.

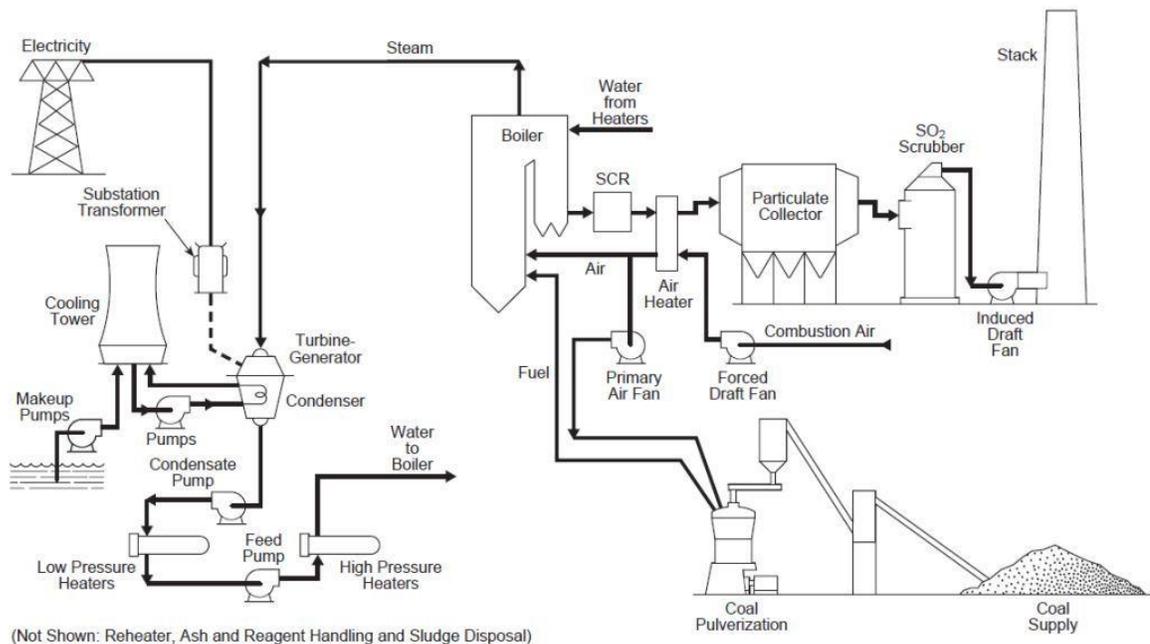


Figure 5. Typical coal plant (Stultz & Kitto, 2005)

The power generation process starts with fuel reception and storage. In many cases, prior to the entrance to the furnace, the fuel has to meet certain requirements of size, moisture content and presence of impurities. Hence, fuel pre-processing may be necessary in the form of size

reduction, metal removal or drying. Moreover, air needed for combustion is supplied by a forced draft fan, after being preheated by an air heater, as a measure to increase the heat transfer efficiency. Once the fuel enters the furnace, combustion takes place and heat is released. The boiler recovers that heat and generates steam at a specified pressure and temperature. Next, gases resulting from combustion, also called flue gases, leave the boiler and flow through the economizer and the air heater. Before exiting through the stack, the flue gases are the target of environmental control techniques, such as particulate material collection, sulfur dioxide (SO₂) scrubbing, heavy metal removal, etcetera. Additionally, ash produced during combustion is collected at the bottom of the furnace and captured from the flue gas draft. At the same time, superheated steam flows through the turbine to create the necessary mechanical power to drive a generator and produce electricity. The electricity produced also has to cover the internal demand of the plant. After leaving the turbine, the steam is converted back to water in the condenser, for reuse as boiler feedwater. Finally, pumps drive the condensed water through economizers to increase its temperature and pressure before its reentry to the boiler, as an additional measure to increase efficiency. From this point, the cycle from water to steam starts over.

3.1. Biomass Combustion

The combustion of biomass is a complex process involving multiple physical and chemical aspects; however, for the purpose of the present work, a basic understanding of the combustion process is necessary. In simple terms, combustion may be regarded as the controlled union of fuel and oxygen to produce useful heat energy. Carbon and hydrogen are among the main combustible constituents of fuel, which once burned will be transformed into carbon dioxide and water vapor. Therefore, fuel properties and combustion applications will determine the nature of the combustion process. Unlike small-scale units, in medium to large scale plants combustion typically takes place in a continuous fashion and forced ventilation is used. (Van Loo & Koppejan, 2008)

The stages which a solid biomass particle undergoes during combustion include drying, pyrolysis, gasification and combustion. First, moisture is evaporated from the fuel at low temperatures using a fraction of the energy released from the combustion process; hence, lowering the furnace temperature and slowing down the process. After that, during the pyrolysis phase the fuel goes through a thermal degradation in an oxygen-starved atmosphere to form charcoal.

Additionally, volatile gases containing hydrocarbons such as CO and CO₂ are released. Next, in the gasification phase a new thermal degradation takes place in the presence of an externally supplied oxidizing agent and gases such as CO₂, H₂O, H₂ and CH₄ are released. Finally, during the combustion phase the fuel is completely oxidized and the resulting hot gas (flue gas) can be used to transfer heat to water in a heat exchanger. (ibid)

Using biomass on an industrial scale poses a series of challenges for power plants at an operational and environmental level. Among these challenges are high moisture content, high content of volatile matter, low bulk density and low ash melting point. A low bulk density increases transportation costs and requirements for storage. Accordingly, biomass densification is commonly applied to cope with this issue. In addition, low ash melting temperatures may cause the formation of mineral deposits on heat transfer surfaces and bed agglomeration in fluidized bed boilers. Moreover, the high presence of volatile matter renders the combustion difficult to control as a consequence of the increase in the ignitability and reactivity of the fuel (ibid). Lastly, the presence of certain elements in biomass such as sulfur, nitrogen and chlorine may cause the formation of pollutants during combustion and corrosion problems.

Plant design is heavily influenced by the type of fuel to be burned. Whether it is coal, NG, biomass or waste, special considerations must be taken in order to achieve optimal performance. For example, physical and chemical characteristics can determine fuel handling and preparation, fuel combustion, recovery of heat, fouling of heat-transfer surfaces, corrosion of materials and air pollution control (Petchers, 2003). It is important to mention that power plant design and combustion technology have been pushed forward as a result of the abundance and low cost of coal as energy source. Therefore, combustion technologies have been mainly developed around making coal combustion cleaner and more efficient. However, current trends demanding the displacement of coal as an energy source motivate scientists and engineers to find creative solutions and alternative uses for existing technologies. In the following section, a review will be presented of combustion technologies originally conceived to burn coal, but that can also be utilized to burn biomass, as demonstrated throughout abundant operational experience over the years.

3.2. Pulverized Fuel Combustion (PFC)

PFC firing is the predominant technology in large-capacity power plants used to provide the

bulk of base-load capacity around the world (Rayaprolu, 2009). This technology makes use of fuel reduced to the size of fine powder and stands out for its improved combustion, increased efficiency, flexibility and ample practical experience, at the expense of high power and maintenance demands from the pulverization equipment. When fuel is pulverized, it exposes a larger surface area to the action of oxidation, thus increasing the combustion rate (Woodruff, et al., 2004). A wide range of fuels can be burned in this mode, as long as they meet requirements of adequate heating value to sustain auto combustion, enough volatile matter to provide ignition of fuel, ease of pulverization and cost (Stultz & Kitto, 2005).

In a typical PFC plant, the fuel is transported from storage and fed to pulverizer mills, where at the same time a primary air fan supplies heated air for drying purposes. Subsequently, the primary air carries the fuel dust from the mills to the burners and into the furnace. Combustion takes place in suspension, when the mixture of fuel and air leaves the burner. Figure 6 illustrates a typical PFC boiler.

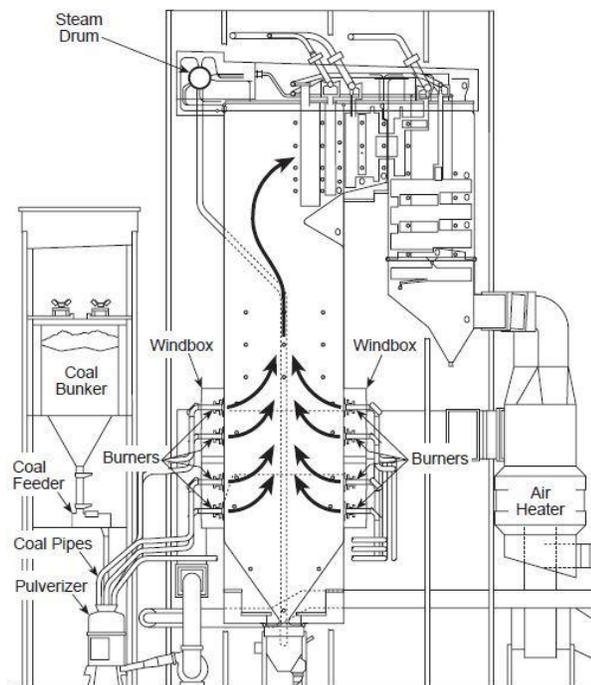


Figure 6. PFC Power Plant (Stultz & Kitto, 2005)

PFC boilers offer different alternatives to comply with environmental regulations. On the one hand, NO_x emissions can be controlled with the use of low- NO_x burners and reducing combus-

tion temperature thanks to larger furnace dimensions and utilization of overfire ports. In addition, abatement of SO₂ is possible with the installation of flue gas desulfurization (FGD) equipment. On the other hand, the use of electrostatic precipitators (ESP) is considered as an efficient method to control fly ash and other particulate emissions.

PFC allows little variations in fuel quality. A 10-20 mm maximum particle size has to be maintained, as well as moisture content no higher than 20% wt (w.b). In order to start up the unit, an auxiliary fuel (oil or NG) is used to raise the temperature of the furnace (Woodruff, et al., 2004). When the temperature reaches a certain point, biomass injection starts and the supply of auxiliary fuel is cut down. Sawdust and fine wood shavings are the most common fuels used on biomass PFC plants (Stultz & Kitto, 2005).

3.3. Stoker Firing

Stoker firing was the first combustion technology intended for large-scale power generation. Its preference ended with the introduction of PFC firing. Nonetheless, it is still used in industrial boilers because of its simple design, low maintenance needs and quick response to load variation (Woodruff, et al., 2004). What is more, stoker firing can handle almost any type of fuel, regardless of moisture, volatile matter and ash content, including all forms of coal, wood, agricultural residues and MSW. Nevertheless, this flexibility added to grate-related variables such as speed, residence time and fuel distribution, render stoker operation susceptible to high variability (Stultz & Kitto, 2005). An example is presented in Figure 7.

The operation principle of stoker firing consists of feeding solid fuel onto a grate where the fuel burns. At the same time, primary air is passed through the grate and also secondary air is injected to enhance combustion and reduce NO_x emissions. Finally, an ash discharge system removes the residues of combustion. There are two general types of stoker systems. The first one is the underfeed stoker, where both fuel and air come from the bottom of the grate. Secondly, there are overfeed stokers, where fuel is supplied from above the grate and air is blown from below the grate.

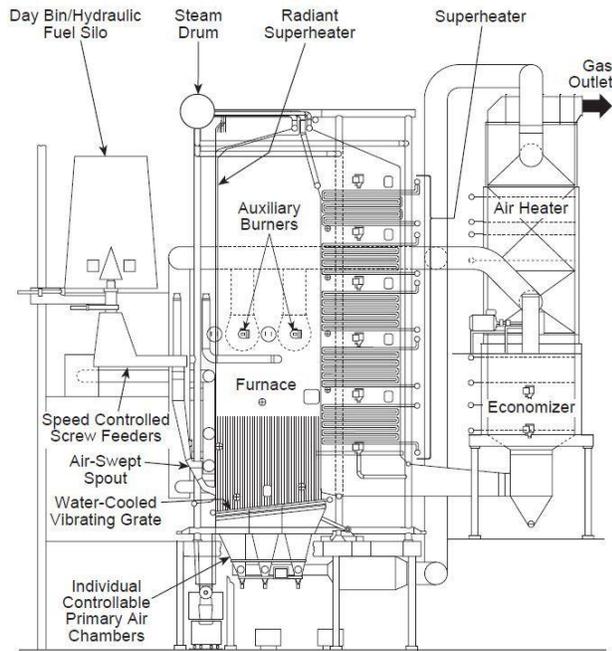


Figure 7. Stoker firing plant (Stultz & Kitto, 2005)

Stoker firing has the potential to burn, in an acceptable manner, biomass featuring high moisture content, varying particle size and high ash content. However, operational experiences have shown that biomass mixtures; for example, wood and straw or wood and grass, can be problematic given their different combustion behavior. This occurrence might be minimized with the utilization of special grates that ensure fuel mixture across them, such as vibrating or rotating grates. On the contrary, poor mixing and uneven fuel distribution on the grate may cause disturbances in the air flow and may lead to heat losses, slagging and higher fly ash amounts. (Van Loo & Koppejan, 2008)

3.4. Fluidized Bed Combustion (FBC)

FBC is the latest addition to fuel firing technology, recognized for its capability to burn low-grade fuels while producing low pollutant levels. In FBC, fuel is burned in a bed of hot, inert particles (generally silica sand and dolomite), suspended by the action of an ascending flow of air and recycled flue gases, also called fluidization gas. The mixture of solid fuel particles and fluidization gas behaves similarly to a fluid, resulting in high heat transfer and most importantly, low combustion temperatures. Procurement of low temperatures in the furnace makes it possible to burn fuels with low heating values, that otherwise would not support a continuous combustion (Stultz & Kitto, 2005). This also prevents the formation of thermal NO_x and ash sintering

in the bed. Additionally, sorbents such as limestone can be added directly to the bed to control sulfur emissions, according to Woodruff *et al.* (2007) reaching up to 90% efficiency in the removal of SO_x .

On the downside, flue gas products of FBC carry high dust loads, demanding the installation of soot blowers and particle collection systems. Besides, part of the bed material is lost with the bottom ash, making necessary the periodical addition of material to maintain the bed. (ibid)

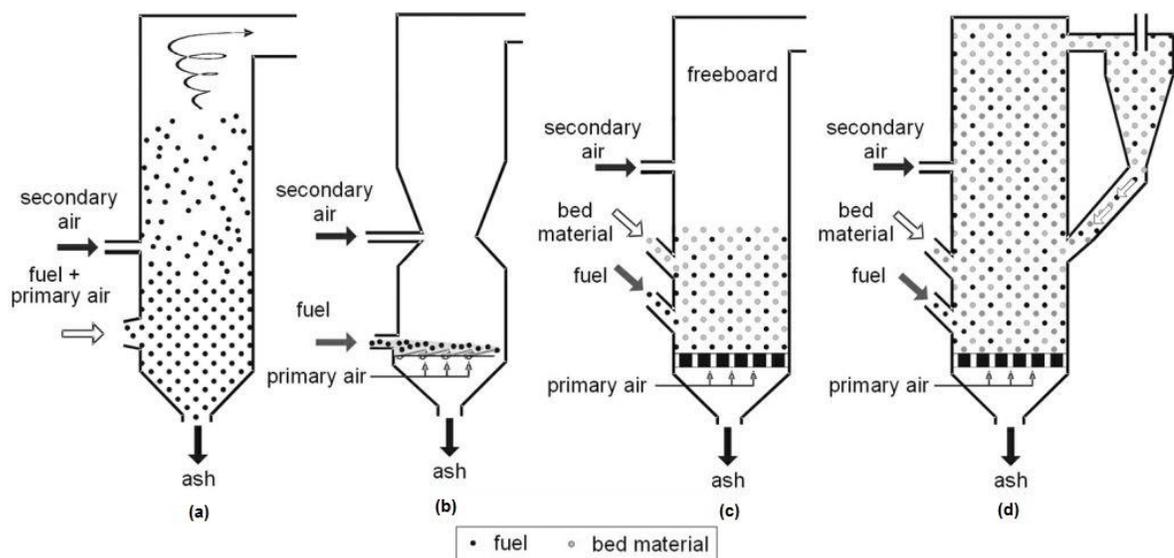


Figure 8. Comparison between different states of fluidization, where (a) corresponds to PF, (b) to Stoker firing, (c) to BFB and (d) to CFB (Van Loo & Koppejan, 2008)

Bed particle size and fluidization velocity determines the state of fluidization. Bubbling Fluid Bed (BFB) and Circulating Fluid Bed (CFB) combustion systems were developed to operate in different states of fluidization. Figure 8 shows a comparison of the transit of particles in the combustion chamber between different combustion technologies. In BFB combustion the flow velocity is low enough to maintain the bed material in the bottom section of the furnace. One of the resulting benefits is the flexibility with regard to particle size and moisture content of biomass fuels. This configuration has shown good results handling fuels with high moisture content; for example, waste, sewage sludge and residues from the paper industry. Meanwhile, CFB plants operate at higher flow velocities and require finer bed particle sizes. In CFB combustion, sorbent and bed material flows throughout the furnace to enter a cyclone separator, where hot flue gases and fly ash are separated from unburnt fuel particles and bed material.

Afterwards, these unburnt particles are reinjected into the furnace. The higher turbulence exhibited in CFB furnaces produces an improved heat transfer and more homogenous temperature distribution. Nevertheless, their larger size and therefore, higher capital costs, might be considered as less favorable aspects of CFB plants. In addition, CFB plants produce a greater dust load and demand stricter particle size requirements compared to BFB installations. CFB boilers are the preferred alternative to burn high-sulfur fuels, such as certain types of coal, petroleum coke and wood waste (ibid). Figure 9 provides an example of the main components of a typical CFB plant.

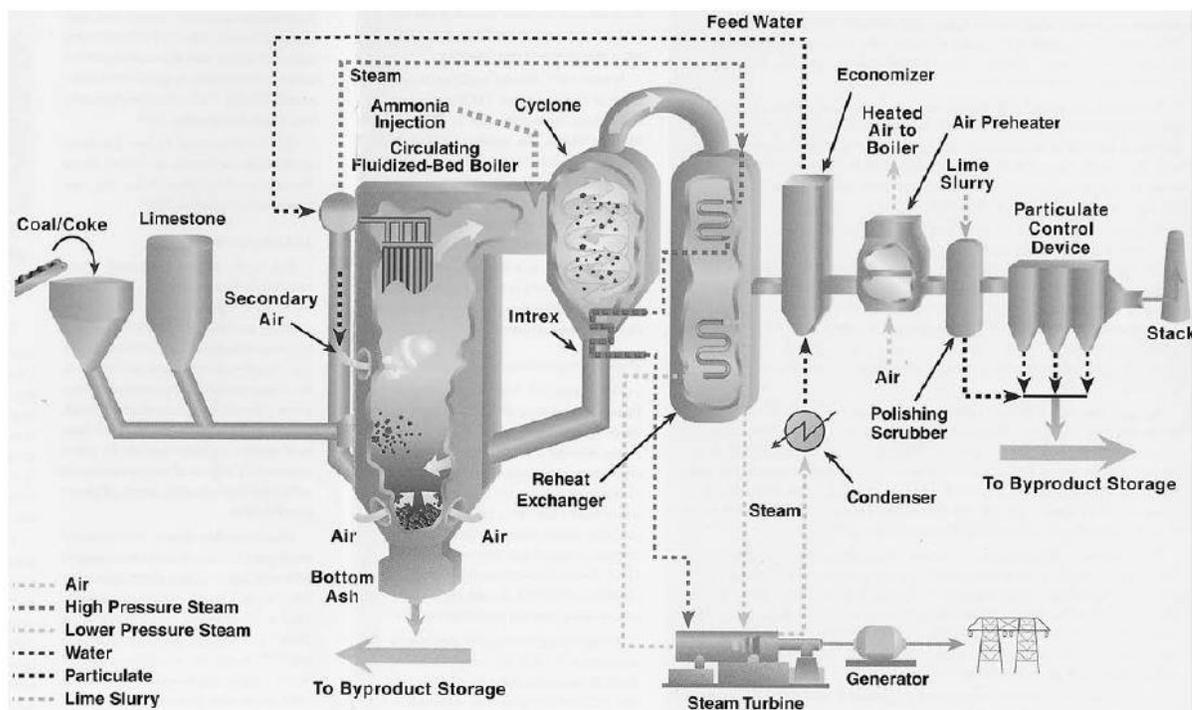


Figure 9. CFB Plant (Woodruff, et al., 2004)

The good mixing of fuel, fluidization gas and bed material present in FBC plants allow the utilization of multiple fuel mixtures, only to be restricted by particle size and impurities content. For this reason, size reduction and separation of metals are often required to ensure a continuous operation. Van Loo and Koppejan (2008) recommend a particle size below 40 mm for CFB units and below 80 mm for BFB installations. It should also be noted that the use of high-alkali biomass fuels in BFB furnaces may result into ash agglomeration. Operation at low bed temperatures prevents ash agglomeration and sintering (Rayaprolu, 2009).

4. PFC TO BIOMASS FIRING CONVERSION

The potential worldwide impacts caused by global warming have been acknowledged by the developed nations (European Commission, 2015a). Concluding scientific evidence shows that fossil fuels for power generation are the main contributors to global warming (EPA, 2012). This fact represents a reason for concern and poses doubts over the energy future of the planet. The European Commission declared that in order to mitigate the impacts of climate change, three measures have to be implemented EU-wide: reducing GHG emissions, improving energy efficiency and increasing the share of energy consumption produced from renewable sources (European Commission, 2015b). Traditionally, RES struggle to compete with fossil energy for a number of reasons; among them, low conversion efficiencies, high costs and high technical risks (Baxter & Koppejan, 2005). Repowering existing power plants by replacing coal with biomass might offer an interesting option to produce renewable energy on account of the potential to decrease GHG emissions, as well as other pollutants (SO_x, NO_x, etcetera). In addition, full-biomass conversion may offer a second life to power installations that have reached a stage when their operation is no longer profitable or in need of costly repairs, by making use of the vast existing investment and infrastructure associated with coal-based power generation. Furthermore, power producers may benefit from adding RES to their portfolios as well as a seemingly low-cost solution to revamping plants reaching their end of life.

At first glance, the idea of full-biomass conversion may not be appealing under the current economic circumstances, from a business point of view. Added to the costs of plant conversion, in most cases biomass comes second to coal in terms of energy density, availability and price. Despite the aforementioned circumstances, the EU is showing a real commitment to mitigate the effects of global warming by setting well defined goals for the reduction of GHG emissions (see Section 2). So far, several power utilities in Europe have adopted co-firing, or the simultaneous combustion of coal combined with a fraction of biomass (generally 5-10% of energy input). Nonetheless, only a small number of full-biomass conversions have taken place, mainly in Denmark, the Netherlands and the UK. A common trend that can be observed in those experiences is the presence of support mechanisms, such as tax exemptions and subsidies that help to motivate the shift towards RES.

Repowering existing power plants and replacing coal with biomass represents benefits for both

the environment and power producers. This has been further demonstrated in a limited number of operational experiences. Still, promoting the growth of bioenergy with the adoption of full-biomass conversion requires a clear understanding of how a plant's O&M is altered and how the plant should be modified accordingly to achieve optimal performance. What is more, the economics of converting an existing power plant to biomass in relation to similar technologies, such as co-firing and newly-built biomass plants, may determine the success or the failure of this technology. Therefore, a critical aspect for interested parties to give any consideration to this technology is the inclusion of cost estimation. To summarize, a detailed evaluation of the technical and economic aspects of this technology constitutes a powerful tool for decision makers to define the energy future for Europe.

5. STATE OF THE ART

This section is a description of common practices and the latest developments in the field of energy technology related to biomass combustion and the repowering of existing coal-fired power plants.

5.1 Biomass Characteristics and their Interaction with Combustion Systems

The first step in the development of biomass combustion technology is a complete understanding of the type of fuel, its physical characteristics and chemical composition. These properties and the quality of the fuel largely determine crucial aspects of the power generation process, such as fuel logistics, combustion technology, efficiency and environmental performance. Utilization of pre-treatment technologies to improve fuel quality is a common practice in biomass combustion, increasing the net cost of fuel. In addition, different combustion technologies are available for different fuel qualities. It must be noted that an inversely proportional relation exists between fuel quality and the complexity of the technology required to successfully burn it, making the utilization of low-quality and therefore cheap biomass fuels suitable for medium to large-scale operation (Van Loo & Koppejan, 2008). Next, the most important properties of biomass fuels and their influence on combustion systems are explained.

5.1.1 Moisture Content

The type of biomass and storage conditions has a strong influence on the moisture content of the fuel, thus it may vary considerably. For example, typically 10% of the weight of wood pellets is moisture; meanwhile, this fraction rises up to 50% for sawdust. During biomass combustion, part of the released energy is used to turn the moisture content in the fuel into water vapor. This means that the dryer the biomass, the more net energy there is available. On the other hand, a fuel with a high moisture content may reduce the combustion temperature and require longer residence times in the furnace. Moreover, moisture affects the volume of flue gas produced per energy unit. (ibid)

5.1.2 Calorific Value

Energy available from biomass can be expressed in the form of High Heating Value (HHV) and Low Heating Value (LHV). HHV, also called gross heating value, refers to the energy released during combustion per mass unit. On the other hand, LHV is also known as net heating value

and refers to the energy actually released during combustion after discounting the heat required for the vaporization of water in the form of moisture and that formed by combustion (Stultz & Kitto, 2005). Correspondingly, moisture content is closely related to the energy value of biomass fuels. For example, HHV for bark is approximately 20 MJ/kg, but its moisture content reaches 50%, resulting in a considerably lower LHV of 8 MJ/kg. At the same time, wood pellets have a HHV of 19.8 MJ/kg and a low moisture content of 10%, resulting in a more than acceptable 16 MJ/kg.

5.1.3 Particles Dimensions and Bulk Density

The Physical properties of fuel play a key role in power generation from biomass combustion. Particle dimension and particle size distribution determine the way the fuel is handled and fed into the furnace and the most appropriate combustion technology (Baxter & Koppejan, 2005). Similarly, a good knowledge of the bulk density and energy content is needed for the optimization of transport and storage of biomass fuel. Depending on the biomass type, fuels are available in the form of bulk material or unit material. Bulk material comprises biomass material with an inhomogeneous size distribution; for example, wood chips, sugar cane bagasse or sawdust. In contrast, unit material features more homogeneous particle dimensions; for example, baled straw, briquettes or pellets.

5.1.4 Presence of Carbon, Hydrogen, Oxygen and Volatiles

Biomass is formed by organic molecules with prevalence of elements such as carbon, hydrogen and oxygen. Firstly, carbon and hydrogen are oxidized during the combustion process to form CO₂ and water. Secondly, part of the oxygen required for combustion to take place is supplied by fuel-bound oxygen. The rest is supplied by air injection into the furnace. Finally, partially oxidized carbon is present in biomass, unlike coal that contains carbon in a more pure form. This explains the considerably higher energy content of coal, compared to biomass. It also explains why woody biomass possesses higher energy content than herbaceous biomass. Furthermore, volatile matter content influences the thermal decomposition and combustion behavior of biomass fuels.

5.1.5 Presence of Nitrogen, Sulfur and Chlorine

According to Van Loo & Koppejan (2008), the concentration of fuel-bound nitrogen is responsible for the formation of NO_x when combustion temperature reaches the zone between

800 and 1000 °C. Nevertheless, additional factors like air supply, furnace geometry and furnace type also have a major influence on the formation of NO_x. These emissions may be controlled following two recommended abatement routes. Primary measures prevent the formation of NO_x by means of a careful control of the air injected into the furnace as primary air and secondary air, as well as the use of flue gas recirculation to improve mixing and to regulate combustion temperature. Moreover, secondary measures can be used when primary measures fail to provide the expected environmental performance by eradicating the NO_x traces from the flue gases. Secondary measures include the installation of either a Selective Catalytic Reduction (SCR) system that injects a reducing agent over a catalyst or a Selective Non-catalytic Reduction (SNCR) system, which injects a similar reducing agent in a separate reduction chamber. Generally, secondary measures are needed only when chemically treated biomass is used; for example, demolition wood.

During the combustion process chlorine content from biomass is vaporised to form mostly HCl, Cl₂ and alkali chlorides. Subsequently, these products are carried by the flue gas and bound to fly ash particles. Nevertheless, as flue gas leaves the boiler and its temperature decreases, HCl vapours tend to condense, forming corrosive compounds and harmful pollutants such as dioxins. For these reasons, limiting the entrance of chlorine to the system is deemed of great importance. (Witkamp, et al., 2013)

Thermal decomposition of biomass produces SO₂, SO₃ and alkali sulphates from fuel-bound sulfur. Similarly to the diffusion of chlorine products, these gases are carried by the flue gas and bound to fly ash. Once cooled, they may condensate on heat exchanging surfaces and produce corrosive effects and fouling.

5.1.6 Ash Content

The major ash-forming elements are silicon, calcium, sodium, magnesium and potassium. These elements can represent up to 12% of the weight of some biomass fuels such as straw. In contrast, iron, aluminium, manganese and heavy metals constitute a minor fraction of the ash-forming elements. Ash content determines the combustion technology applied and de-ashing strategies. Fuels with a low ash content are preferred in power generation applications because their utilization may result in lower emissions and lower cleaning frequency of the

boiler, as a consequence of lower fouling incidence and higher efficiency of the dust precipitation equipment (Stultz & Kitto, 2005).

Potassium, phosphorus and magnesium are commonly used as plant nutrients and their presence in ashes resulting from biomass combustion, an otherwise waste product, make them apt to be marketed as fertilizer. However, since only a small fraction of heavy metals are carried off by flue gases and the rest remain with ash, their presence, specially zinc and cadmium, may affect ash commercialization.

5.2 Considerations for Full-Biomass Power Plant Conversion

Despite an apparent similarity, biomass and coal feature considerably different behaviors when combusted. These differences are accentuated even further on industrial scale combustion systems. Multiple technical aspects must be addressed when burning biomass in existing coal-fired power plants, in order to reduce the risk of interference with the operation of the fuel feeding system, boiler and environmental control equipment. Next, the main technical challenges associated with full-biomass conversion are presented.

5.2.1 Fuel Preparation, Storage and Delivery

Experiences repowering existing coal-fired power plants have shown that the main source of technical problems is derived from the reception, storage and handling of biomass fuel. The nature of these problems has a direct relation to the characteristics of the biomass used. In most cases, biomass features low bulk density, high moisture, hydrophilia and difficulty for size reduction. Additionally, generally biomass energy density is much lower compared to coal, representing higher requirements for storage and on-site handling technologies, in proportion to its heat contribution.

When considering the storage and handling of biomass materials, moisture content is one of the key properties. It is of special importance because of the risk of self-ignition caused by microbial activity when biomass with moisture content higher than 20% (w.b.) is stored for long periods. In addition, long-term storage of wet biomass can also lead to the loss of dry matter and a significant deterioration in the physical quality of the fuel, as well as high dust and spores concentrations, creating health and safety hazards. In order to minimize the aforementioned risks, four strategies have been devised to attenuate biological activity during storage. The first

one is reducing the surface area available for biological activity by piling the biomass in billets or large pieces. Another strategy is the use of fungicides, followed by pre-drying of the biomass fuel. Lastly, the use of forced ventilation to reduce the temperature of the stored biomass is also recommended. It has to be noted that any of these measures will increase the net cost of fuel. (Livingston, 2010; Van Loo & Koppejan, 2008)

Another challenge related to the utilization of biomass as fuel is the difficulty to characterize the flow behavior. On the one hand, granular and pelletized materials may be handled with no difficulties as long as their moisture content remains at low levels. Even so, pellets are not exempt of issues. For example, wood pellets have the capacity to absorb moisture from the surrounding air, as a result they can grow mold and swell when stored for a long time, making their handling difficult. In this case, a reduction of the storage time is recommended, as well as providing dry conditions during storage. Unsurprisingly, the varying particle size and moisture content present in woody biomass products, like wood chips and sawdust, make their handling also challenging. On the other hand, bales might result as an effective method to handle, transport and to store herbaceous biomass and straw. However, bales require specialized equipment. (Van Loo & Koppejan, 2008)

A critical aspect to consider when handling and storing biomass is the production and accumulation of dust. Dust generation represents both fire and explosion hazards. According to Livingston (2010), the emission of dust might be controlled by means of extraction systems and water misting, the latter with the downside of increasing humidity inside the store. Furthermore, it is recommended to install explosion vents and fire suppression systems.

5.2.2 Size Reduction

In conventional PFC plants, coal size reduction takes place in coal mills thanks to the brittle fracture mechanism. Nevertheless, biomass possesses poor properties in this regard, causing retention of particles within the mills and limitation of the feeding rate (Obenberger & Thek, 2010). Power consumption from the milling equipment may also increase. Baxter and Koppejan (2005) consider that reducing biomass to the same size or shape as coal is unfeasible and unnecessary.

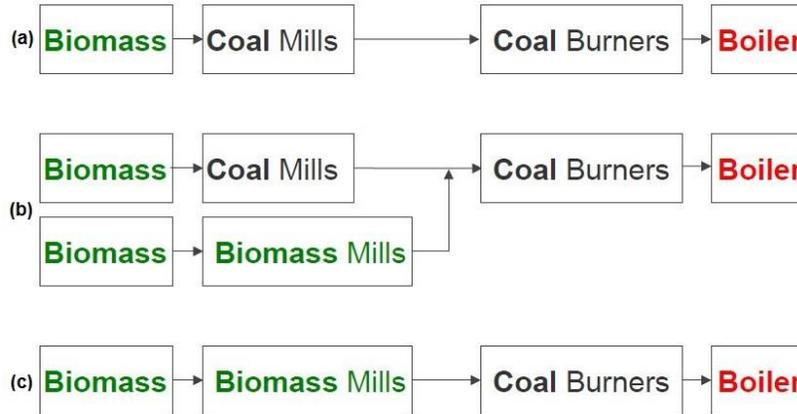


Figure 10. Main options available for biomass size reduction (Livingston , 2013)

As shown in Figure 10, there are three main routes available for the size reduction of biomass in power plants originally designed to burn coal. A safety issue that needs to be accounted for when size reduction of biomass takes place in coal mills is the use of dry air to reduce the moisture content of the fuel. Release of combustible volatile matter occurs at lower temperature on biomass, in comparison to coal. Therefore, a modification of the mill operation parameters is necessary to reduce the risk of explosion. Despite the risk and limitations, size reduction of chipped, granular and pelletized biomass using coal mills has been successful in a number of places in Europe (Livingston, 2010).

5.2.3 Performance and Integrity of the Boiler

Once more, the varying properties of biomass fuels pose a series of challenges to achieve an efficient transformation of fuel into useful energy. On the one hand, biomass features higher reactivity and lower particle density compared to coal, resulting in higher combustion rates. Increased combustion rates allow the utilization of particles of a coarser size distribution. On the other hand, excessive moisture will heavily influence the boiler's maximum achievable load and efficiency. (Baxter & Koppejan, 2005)

Generally, biomass possesses low ash content; however, the ash behavior may differ from coal ash. Biomass ashes have low fusion temperatures and high levels of alkali metals, especially potassium (Van Loo & Koppejan, 2008). These compounds have a tendency to form ash deposits in the radiant section of the furnace (slagging) and also on the convection pass (fouling). Power plants that use biomass fuels with high ash contents have to be shut down periodically for cleaning work, since the formation of deposits has the potential to hinder a correct operation.

Moreover, alkali metals presence in fly ash influence operational issues on environmental control equipment, such as SCR. Multiple biomass combustion experiences around Europe reveal that alkali metals have the potential to deactivate the catalyst. These metals might cause poisoning of the vanadium-based catalyst present in all SCR commercial systems (Baxter & Koppejan, 2005). The use of water jets to clean the catalyst blocks is recommended. Another recommended strategy is the installation of the SCR equipment at the end of the flue gas path, before it exits through the stack, to obtain an extended catalyst life and keep NO_x emissions low. Nevertheless, this solution is far from perfect, because at the point of installation of the SCR flue gas may not have high enough temperature for the catalyst to perform at a good chemical efficiency (Schaaf, et al., 2010).

High efficiency and low pollutant emissions are the result of a complete combustion of fuel particles. Complete combustion can be achieved with a fine-tuning of the combustion process and a thorough knowledge of the chemistry of the biomass used. The main variables to be adjusted are temperature, residence time, stoichiometry and mixing. First, combustion temperature must be high enough to support a self-sustained operation. Second, sufficient residence time allows fuel particles to liberate all their chemical energy. Third, the presence of air is crucial in combustion processes; for this reason, air must be supplied proportionally to the fuel feeding rate. Finally, efforts must be made to ensure a homogeneous mixing of fuel and air and to avoid fuel-rich zones in the furnace. Setting of these four parameters will be closely related to both the combustion technology and the biomass fuel used. (Van Loo & Koppejan, 2008)

5.2.4 Pollutant Emissions

In general terms, converting existing coal-fired power plants to biomass is deemed beneficial in regard to pollutants released to the environment. Resulting emissions of CO₂, SO_x, NO_x and mercury from repowered plants are much lower when compared to traditional coal-fired plants.

SO_x emissions vary in proportion to the sulfur present in the fuel. Considering that most biomass fuels contain lower sulfur content than coal, a considerable reduction of this pollutant is witnessed in converted facilities. Similarly, biomass fuels contain low levels of fuel-bound nitrogen that may result in an apparent reduction of NO_x emissions. However, this product of combustion is formed by multiple mechanisms, therefore emissions could increase, decrease or remain the same, depending on fuel, firing conditions and operating conditions (Baxter &

Koppejan, 2005).

In relation to particulate emissions, fly ash products of biomass combustion represent different chemical composition and size, providing a technical challenge for their control. Regardless that resistivity of biomass fly ash is typically within the operating range of most dust precipitation equipment, such as ESP, the higher fraction of submicron particles in fly ash reduces the collection efficiency. Schaaf *et al.* (2010) suggest a series of measures to maintain the efficiency of particle collection, such as adding fields to an existing ESP or installing a new unit. Furthermore, the superior flue gas flow rates observed in biomass combustion might exceed the design values for baghouse filters, thus requiring their replacement.

5.2.5 Ash Utilization

Ash products of coal combustion and co-firing of biomass and coal with shares up to 20% have been successfully used for a number of applications, including concrete aggregate, asphalt filler and fertilizers. Currently, the European technical standard EN-450 is being revised to contemplate the use of fly ash from co-firing percentages up to 50% as an additive for concrete. Nonetheless, residues from 100% biomass combustion report different physical characteristics and chemical composition, hence they may not meet the requirements of the aforementioned uses, originally intended for coal ashes (van Eijk, et al., 2012). Therefore, research is in progress to identify and develop alternative uses for biomass ashes.

5.3 State-of-the-art Fuels

The choice of biomass is a crucial aspect of the repowering of an existing coal-fired power plant. Ideally, the selection of fuel must render the lesser impact on O&M and require limited modifications/additions to the plant. At the present time, it can be observed that the most commonly used biomass fuels are wood chips and wood pellets. On the one hand, wood chips are used when the power plant features a combustion technology different to PFC and/or in case the source of biomass is in the vicinity of the plant. On the other hand, wood pellets are often used in PFC plants and/or when the plant is located far from an economic fuel source (Witkamp, et al., 2013).

Densification of biomass in the form of pellets offers multiple advantages compared with other forms of biomass. Wood pellets feature consistent quality, low moisture content, high energy

density and homogenous size and shape. These properties facilitate biomass handling, transport and storage, increasing the appeal for power producers. Pellets are expected to become one of the fastest growing energy sources, with a tenfold increase in the EU alone (Dahlquist, 2013).

A new development in the field of biomass densification is the production of refined pellets. This classification includes torrefied pellets and steam explosion pellets. Refining of biomass offers significant benefits for combustion systems and for the economical use of raw biomass. This technology makes biomass more consistent with coal due to the improvement of energy content, grindability and storability. Therefore, the use of refined pellets may improve transport logistics and lessen the requirement for cost-intensive plant modifications. Table 2 shows a comparison of the main properties of state-of-the-art fuels.

Table 2. Properties of Wood Chips, Wood Pellets and Refined Wood Pellets. Modified from (Khodayari, 2012) and (Witkamp, et al., 2013)

	Wood Chips	Wood Pellets	Torrefaction Pellets	Steam Explosion Pellets
Moisture Content (%)	35-45	8-10	1-7	
LHV (MJ/kg)	9-12	16-18	20-24	17-19
Volatiles (%)	75-85	75-85	55-75	70-80
Bulk Density (kg/m³)	200-250	500-650	550-850	700
Energy Density (GJ/m³)	~3	11	13-15	
Grindability in Coal Pulverizer	Not Possible	Limited	Good	Good
Hydroscopic Nature	Hydrophilic	Hydrophilic	Hydrophobic	Hydrophobic
Densification without Binders	N.A	Proven	Depends	Good

5.3.1 Wood Chips

Biomass fuel in the form of wood chips comprises all the biomass products obtained from a forestry source which undergo a size reduction process. Typically, particle size ranges from 0.2 to 15 cm. In addition, the moisture content may vary greatly according to the biomass type, season and origin. (Witkamp, et al., 2013)

5.3.2 Wood Pellets

Wood pellets are mainly produced from dried and milled wood chips. Nevertheless, sawdust can also be used to manufacture pellets, but its high moisture content turns it into a less favorable alternative. The European standards CEN 14961 and CEN 14588 describe all the relevant properties of wood pellets.

5.3.3 Torrefied Pellets

Torrefaction uses high temperatures and pressures to partially break down the fibrous structure of biomass products. As a result, torrefied fuel becomes easier to mill. Additionally, torrefied pellets present a higher calorific value when compared to regular pellets. Another benefit is that torrefaction induces a hydrophobic behavior in biomass, thus eliminating the need for climate-controlled, indoor storage. The aforementioned characteristics have the potential to improve the efficiency of transport and handling systems.

5.3.4 Steam Explosion Pellets

In a process similar to torrefaction, steam explosion cause the destruction of the fibrous material present in biomass. However, pellets produced with this technology present higher volatiles presence and lower heating values. On the other hand, no binding agents are required for pelletizing due to the higher lignin content.

Documented experiences in Northern Europe reveal that provided a uniform particle size distribution of biomass fuels, acceptable results in terms of combustion efficiency and emission levels can be achieved. What is more, the reactive behavior of biomass during combustion makes the particle size reduction to the same level as pulverized coal unnecessary. For this reason, the primary particle size of the sawdust used to manufacture pellets is specified by the power plant operator since modified coal mills may only reduce pellets back to sawdust. On the other hand, an irregular particle size distribution may lead to an increase in unburned fuel presence in both bottom and fly ash. Furthermore, trials in Northern Europe have shown no significant alterations of furnace heat absorption or flame shape. In most cases, combustion of pellets required no major boiler modifications. (Obenberger & Thek, 2010)

Despite the multiple benefits provided by refined pellets, their utilization is not yet widespread because of the still-in-development status of their technology. Commercial availability of refined

pellets is still limited and there is a lack of well-defined quality standards. Moreover, further R&D is required to establish refined pellets as a true competitor to wood pellets. (Witkamp, et al., 2013)

5.4 Case Studies

In this section, two experiences with repowering of existing of coal-fired power plants will be presented. The goal of the introduction of case studies in the present work is to identify the main components of the power plant subject to modification or replacement. Additionally, the review of repowering experiences might provide a real-world insight and reveal aspects that may have been overlooked in the previous sections.

5.4.1 Atikokan Generating Station

Atikokan is a pulverized coal power plant located in the province of Ontario, Canada. It has a single generating unit, with an installed capacity of 211 MW and used low-sulfur lignite as fuel. In September of 2012, Atikokan stopped burning coal and a conversion project took place to use dry wood pellets as fuel. Conversion of Atikokan obeyed the plans for the province of Ontario to phase out use of coal for power generation by 2014. Ontario Power Generation, the owner of the plant, decided to greenlight the conversion proclaiming the benefits that such a project would bring to the region in terms of GHG emission reduction, while re-using existing facilities. First trials took place in October of 2013 and the first batch of pellets was burned in May of 2014. With an investment close to \$170 million Canadian dollars, the conversion of Atikokan required the adjustment, replacement or installation of new systems, including fuel reception and storage, fuel processing, boiler, ash handling, process control and safety systems. Next, these modifications will be presented in more detail.



Figure 11. Atikokan Generating Station (Boyko, 2014)

As seen in Figure 11, fuel reception and storage are the most noticeable modifications to Atikokan. A new unloading facility was erected, where self-unloading trucks deposit the pellets brought from locations no farther than 200 km. Once unloaded, pellets are stored into either of the two 5,000 ton capacity silos; however, silos can be bypassed when direct fuel feed is deemed necessary. Prevention of dust-related hazards is a priority in Atikokan, for this reason, silos are equipped with dust control equipment, explosion vents and temperature monitoring systems. In addition, silos have aeration and inert gas injection capabilities. Finally, a bottom fed conveyor belt takes the pellets from the silos to in-plant surge bins.

Vertical roller mills, originally used to pulverize coal, were modified to operate at higher velocities and to reduce the classification of particles. When introduced into the mills, the pellets break into constituent particles during the first pass. Additional passes result in no further size reduction. What is more, low moisture content of pellets requires modifying mill operation in order to reduce primary air flow and temperatures. In consequence, the installation of an air cooler was necessary to temper the primary air to an adequate temperature, avoiding the risk of fuel self-ignition. Mills are also fitted with explosion suppression and dry chemical fire suppression systems. There also exists an opportunity to increase efficiency by means of transferring the rejected heat to the feedwater system.

No changes were made to boiler pressure parts or to the boiler openings. However, all the

burners were replaced by new Doosan Babcock burners modified to burn biomass. Also, the existing flue gas recirculation fan is still used to regulate temperature in the furnace. In the ash disposal system, the existing pneumatic conveyor was replaced by a new drag-chain conveyor of continuous action. Similarly, ashes are continuously evacuated from collection hoppers on the ESP. Ashes received approval to be taken to a local landfill. Other important modifications worthy of mention were performed on the process control system, where a completely new control room was built. Also, Atikokan now possesses a rigorous cleaning regime for horizontal surfaces and conveyor systems to prevent the accumulation of dust.

5.4.2 Tilbury B Power Station

The history of Tilbury B starts back in 1967 with the construction of four 350 MW units equipped with PFC boilers designed to burn bituminous coal. This power station is located on the north bank of the river Thames in Essex, England. In 1998, one of the units was mothballed, reducing the total installed capacity of the power station to 1050 MW. Later, in 2007 Tilbury opted out of the Large Combustion Plant Directive (LCPD), meaning that the plant was not going to comply with the emission limits imposed by the EU. Since then, the plant was allowed to operate for a maximum of 20,000 hours and must close by the end of 2015. Npower, the owner of Tilbury, took this as an opportunity to learn by doing and decided to embark themselves on a conversion project and use the remaining 8,000 hours of operation left for Tilbury.

Npower found multiple advantages in the conversion of Tilbury, most important of all, giving a second life to the power plant and extending the life of their assets. The existing deep water dock allows for the reception of large quantities of fuel carried by ships, and good transmission access results in low connection charges. Initial trials in 2010 using wood pellets revealed that reusing the existing fuel route and coal mills, stable combustion could be achieved with minimum investment. On the other hand, the allowance of Renewable Obligatory Certificates (ROCs) for 100% biomass conversion offered an alternative for capital recovery. Lastly, the use of biomass is in line with the objectives of the UK for the reduction of GHG emissions.

Conversion was planned in two phases. The first one included design, implementation and operation during the remaining 8,000 hours. In the second phase, Npower would look for the issue of a new license to operate, following new plant standards. In March 2011 coal was burned for the last time. Once the conversion work was completed, power generation from

biomass started in December of 2011. Modifications were made to mills, classifiers and burners in order to optimize combustion and to improve flame stability. On the other hand, dust suppressing vacuum unloaders were installed, as well as dust silos and an elutriator system. Figure 12 shows a top view of Tilbury and illustrates the main changes made during its conversion to biomass.

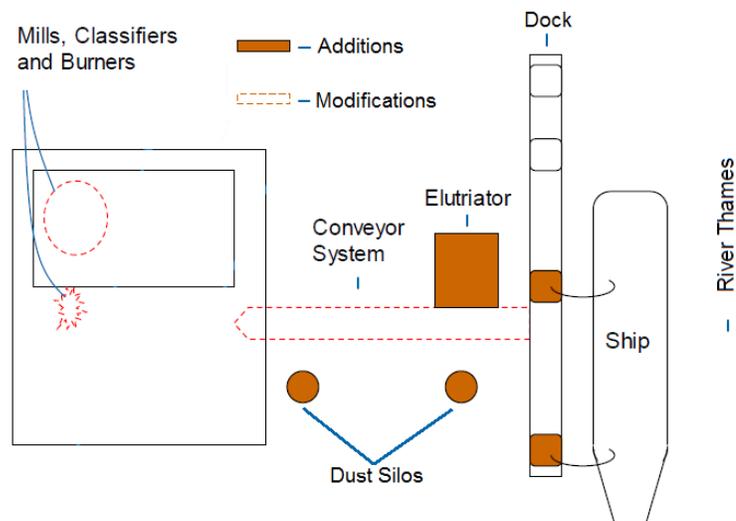


Figure 12. Conversion of Tilbury B (Jamieson & Dyson, 2014)

No long-term storage was deemed necessary; ships loaded with 12,000 tons of wood pellets brought from the USA were conveyed to the fuel bunker. Nonetheless, the scale of operation of Tilbury, where a total of 450 tones per hour of fuel was used by the three units demanded a faster method to deliver fuel to the bunkers. For this reason, the existing continuous ship unloader was replaced by vacuum unloaders that also offered dust suppression. Furthermore, an elutriator was installed at the reception point to improve the control of dust emissions. Other measures taken to prevent fire and explosion hazards were vacuum extraction, dust seals, belt speed control and gas detectors. Finally, the different flow behavior of pellets required the alteration of hopper profiles in many locations. On the other hand, in an effort to avoid the contact of ash with water, ash was captured and transported by vacuum systems.

Regarding the processing of pellets reusing the vertical roller mills, the overall experience was positive. However, it was demonstrated that burn efficiency was very susceptible to grind quality. In addition, the throughput was low due to the effect of turbulence in the mills. Hence, mill operation was adjusted to increase air flow separation. Even more, manipulation of grinding

depth and pressure improved grind quality.

Operation at Tilbury exceeded everyone’s expectations (Jamieson & Dyson, 2014). Nevertheless, issues soon appeared. On February of 2012 a fire was caused as a consequence of dust accumulation and hot particles falling into the fuel bunker. Months later, the three units went back online after a thorough review of all risk assessments and the subsequent implementation of risk reduction measures. A conversion project of the type and scale of Tilbury represented a challenge. Even so, the solutions conceived worked in an acceptable manner. Table 3 presents a performance comparison of the plant using coal against biomass. The most remarkable outcomes of the conversion of Tilbury were the significant reduction of CO₂, NO_x and the complete elimination of SO_x. On the other hand, the volumes of ash produced while using biomass were also notably reduced.

Table 3. Performance Comparison at Tilbury B

Operational mode	Coal	Biomass
Station rated output	1,062 MWe	750 MWe
Station average efficiency at rated output	38.5%	37% (Willans Line)
Station emissions and lifecycle CO ₂ reduction	0.81mt/TWh CO ₂ – baseline	0.11-0.18mt/TWh CO ₂ (78-87% reduction)
Emissions of Oxides of Nitrogen	480m g/m ³	175 – 250 mg/m ³
Emissions of Oxides of Sulphur	800 m g/m ³	0 mg/m ³
Ash	40kt/TWh	4kT/TWh (90% reduction)
Stack Dust	20-40 m g/m ³	10 -15 mg/m ³

Operational experience at Tilbury provides valuable lessons. Cost-intensive additions such as the vacuum unloader and the elutriator worked as expected; however, dust was still an ongoing issue. Also, output and efficiency of the units was better than expected due to the excellent milling performance, while load factors of 90% were achieved. In July of 2013, Npower decided not to continue with the second phase of conversion citing the ineligibility of the project for additional support mechanisms.

5.5 Coal-Based Power Generation in Europe

Coal continues playing a dominant role in energy production for the EU, accounting for a third

of the power generation (EURACOAL, 2014). Additionally, a great number of coal-burning facilities are in operation, ranging in capacities as small as 4 MW to large capacity installations producing 1,100 MW or more, adding up a combined capacity of 140,468 MW and representing 28% of the total installed capacity. Despite the significant increase in recent years of renewables and gas-powered stations, coal remains an important primary energy source for efficient and reliable power generation. Abundance, affordability and availability make coal an attractive choice for this purpose. Many companies have planned new construction projects to replace older, less efficient plants and to keep the pace with the increase in electricity consumption. As a result, not only carbon dioxide is going to be reduced, but also other pollutant products of coal combustion.

According to Ambrosini (2005), large-size coal power plants are commonly designed to operate at least for 25 years. However, units older than 25 years are commonly found and account for more than 75% of the worldwide coal-firing installed capacity. In an attempt to maximize their investment, plant operators extend the unit's life to 40 years; in some cases, even exceeding 50 years of operation. Observing the European case, it is revealed that approximately 69% of the installed capacity corresponds to coal plants built more than 25 years ago (GlobalData Power, 2015). A common approach to power plant life extension is the refurbishment of boiler components, upgrades to the turbine and installation of modern pollution control equipment. Hence, life extension projects represent a significant capital investment and considerable downtimes. Consequently, it may not be economically feasible to extend the life of smaller units. Figure 13 illustrates the age and size profile of the coal-firing fleet existing within the EU. It should be noted that the figure includes only plants currently in operation. Facilities under construction, retired, shutdown or mothballed are excluded.

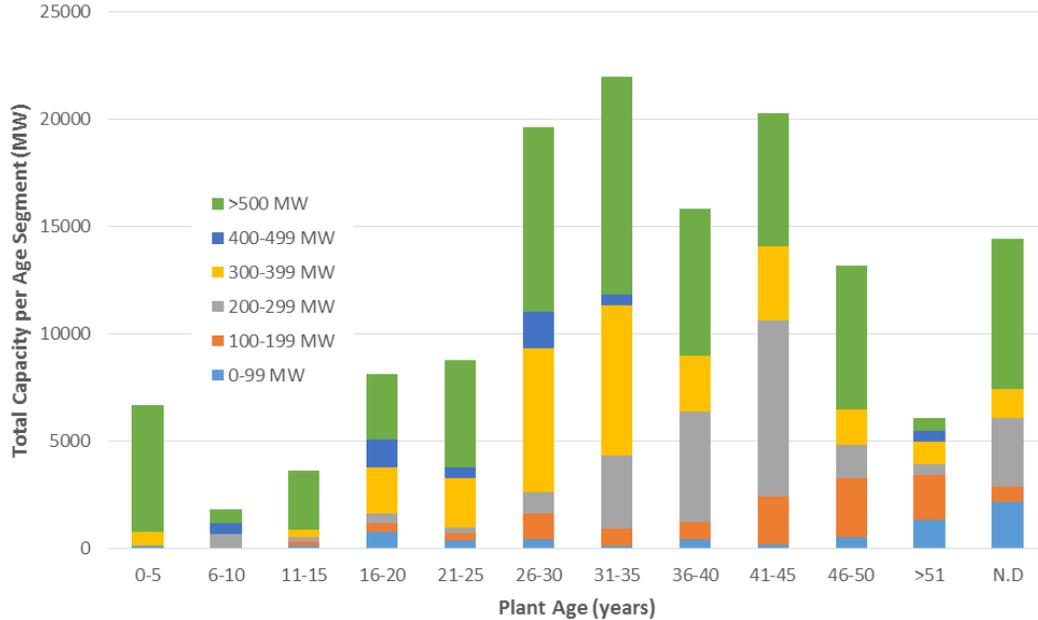


Figure 13. EU's Coal-fired Power Plant Installed Capacity Classified by Age and Size. Modified from (GlobalData Power, 2015)

In contrast, some plant operators may consider that it makes no economic sense to keep running a coal-fired power plant once it has reached the end of its design life. Some may estimate paying for costly upgrades to keep old plants in operation as a bad investment, considering the increasingly demanding environmental legislation and the availability of affordable, cleaner technologies. In addition, dated units usually exhibit performance below the standard, causing additional downtime for maintenance, repairs and overhauls. In some cases, efficiency of old units may not allow producing power at competitive prices during most times of the year (Cleetus, et al., 2012). This occurrence presents itself as an unprecedented opportunity for the development of clean technologies by repowering power plants to burn exclusively biomass, by making use of the numerous existing facilities and equipment to produce power from a renewable source. Furthermore, this solution may also benefit from land development, permissions and licenses issued to existing power plants. As seen of Figure 13, the bulk of the currently active coal-fired power plants in the EU are placed in an age range between 26 and 45 years, an age group that results of particular interest for the present work. It can be assumed that a large number of power stations shall be decommissioned or upgraded in the near future, thus creating an adequate scenario for the shift towards RE.

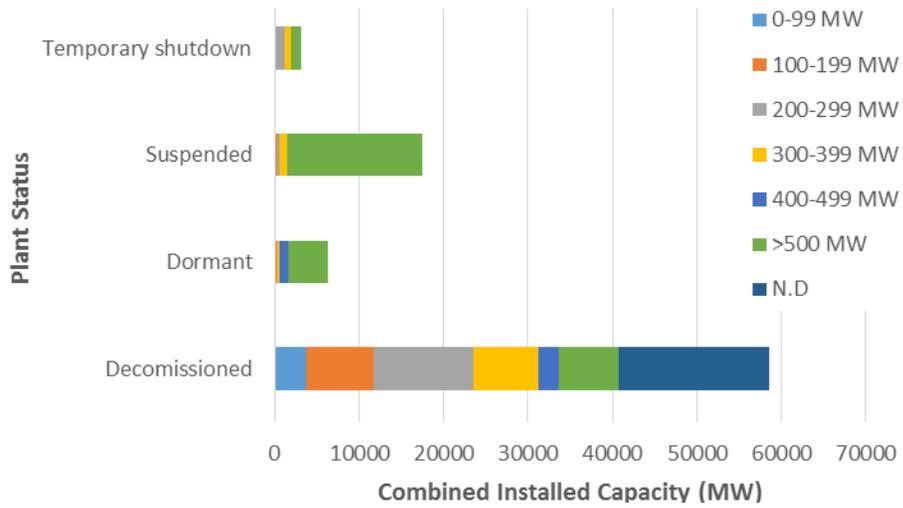


Figure 14. Other Potentially Usable Plants. Modified from (GlobalData Power, 2015)

In the same way, there exists an important number of power plants with potential to be repurposed to burn biomass. These are facilities that for either technical, political or economic reasons have been decommissioned, shutdown, suspended or remain dormant. As seen in Figure 14, these numbers should not be neglected.

6. EVALUATION OF TECHNICAL FEASIBILITY

Presently, only a limited number of experiences with power plant conversions to biomass are to be found. For this technology to become a competitive alternative to coal-firing, efforts must be made to produce comprehensive technical and scientific data. The first step towards this goal is understanding power plant operation. More precisely, a firm grasp on how fuel determines every major aspect of plant design and performance. Just then, it is possible to estimate the implications of the fuel shift to biomass. In the following section, the technical feasibility of power plant conversion is evaluated. For this purpose, in this study an existing coal-fired power plant will be selected as a base model for the implementation of the proposed technology. In addition, a calculation model is developed using Microsoft Excel to determine crucial aspects of plant design and performance. Results for the base model and for the same plant running solely on biomass will be compared. Lastly, the data obtained will be the subject of discussion and recommendations.

The calculation model has been built with a fair level of detail, in an attempt to resemble as accurately as possible the actual configuration of the selected power plant. Nonetheless, given the iterative nature of these calculations and due to the intricate network of parameter interrelations, some compromises had to be made for the sake of simplicity and computation speed. Also, since comprehensive power plant technical data is rarely made public, multiple parameters were assumed based on either experience on typical values, similar trials or literature review.

The central assumption for the estimation of the technical feasibility of plant repowering is that biomass, possessing an inferior heating value when compared to coal, will require a larger heat transfer area to produce the same amount of power. As it has been illustrated in the previous sections, biomass combustion differs considerably from coal's. On the one hand, the characteristic chemistry of biomass makes necessary the utilization of higher amounts of air for combustion; therefore, the volume of flue gases is increased as well as their flow velocity. On the other hand, the inferior energy content of biomass fuel represents a smaller energy input per mass unit to the boiler. Correspondingly, if two identical boilers burning equal amounts (on a mass basis) of biomass and coal are considered, the power output of the biomass boiler will be significantly lower as a result of the insufficient heat transfer area to cool down the flue gases

and the poor heat transfer caused by a lower energy input.

Despite the fact that key technical data from Unit 1 is available, dimensioning of heat exchangers remains unknown. For this reason, a calculation model is developed to quantify the heat transfer area and other parameters that might serve to establish valuable comparisons between Unit 1 operating business as usual against the same boiler running on biomass. Once sizing of the different heat exchangers in the base model is determined, an iterative process is performed to estimate different performance parameters from Unit 1. A detailed account of the calculation procedure is presented in Appendices 1 and 2.

6.1 Study Unit Description

In order to evaluate the technical feasibility of the conversion to biomass of a coal-fired generating station, a PFC thermal station located in Eastern Slovakia was selected as a base case. Situated in the Michalovce district, Power Plant Vojany is the largest thermal power plant in Slovakia, with an installed capacity of 1,320 MW. This capacity is produced by six coal-fired units, which deliver 110 MW each and six heavy oil/gas-firing units, also delivering 110 MW each. Vojany I Unit 1 was selected due to the availability and completeness of its technical data. In addition, it unites the characteristics of age, size and condition that result of interest for conversion purposes (see Section 5).

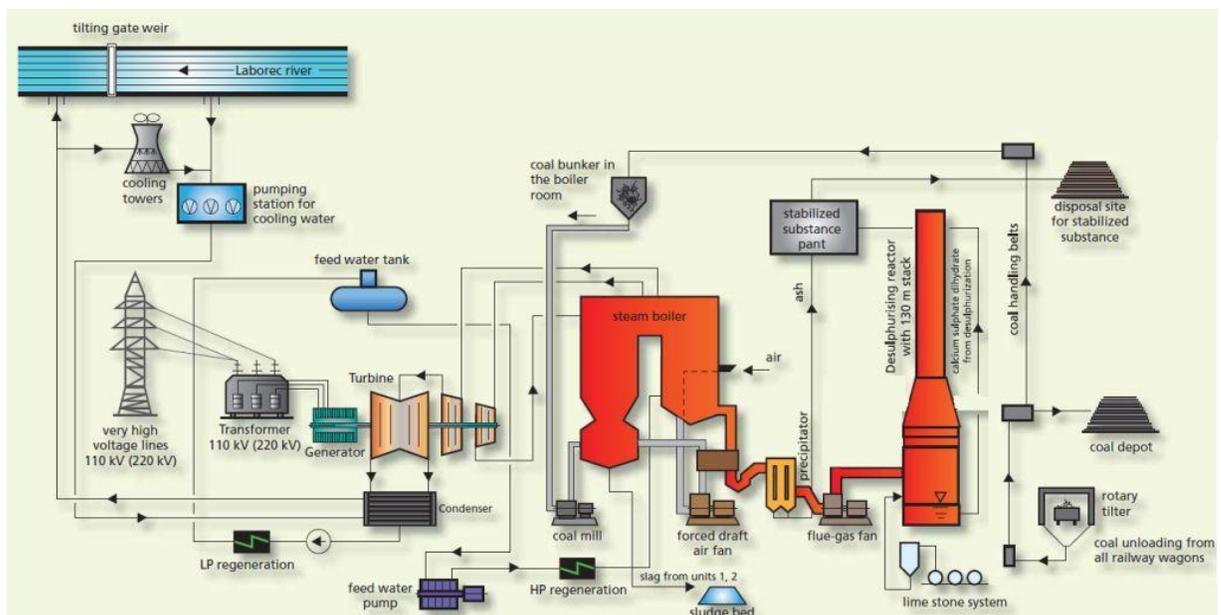


Figure 15. Vojany I Unit 1 (Slovenské Elektrárne, 2011)

Unit 1 is characterized as a natural circulation, sub-critical boiler. Fuel is fired by an array of ten burners located on the front and back walls of the combustion chamber. A wet bottom furnace design captures the ash products of combustion. Additionally, fuel size reduction takes place in two drum ball mills and it is later stored in a pulverized coal bunker. Primary air fans supply air for combustion. Since its commissioning in 1966, Unit 1 has been subject to a number of modifications to improve its environmental performance. These upgrades include the replacement of the mechanical precipitator with an electrostatic one in the late 80's and the installation of low NOx burners, ammonia injection and desulphurization during the late 90's. Figure 15 shows the main systems present in Vojany I Unit 1.

Another aspect of importance is the fuel delivery system, handling and storage. High grade coal from Russia and Ukraine is delivered by train and unloaded by a rotary tilter. After that, fuel is transported to a coal yard by belt conveyors. The coal yard has the capacity to store 60,000 tons of fuel, enough for 60 days of continuous operation. Next, a summary of the main technical data from Unit 1 is presented.

Table 4. Vojany I Unit 1 Technical Data (Slovenské Elektrárne, 2011)

Boiler type	Natural circulation, PFC firing
Main steam flow	97.22 kg/s
Main steam pressure	13.6 MPa
Main steam temperature	540 °C
Reheated steam pressure, inlet	3.2 MPa
Reheated steam temperature, inlet	357 °C
Reheated steam pressure, outlet	3 MPa
Reheated steam temperature, outlet	535 °C
Feedwater temperature	240 °C
Fuel consumption	12.08 kg/s
Efficiency	88%
Turbine output	110 MW
Fuel	Half-Anthracite with low volatile content
HHV (a.r)	35.03 MJ/kg
LHV (a.r)	24.73 MJ/kg
Proximate analysis	
Moisture content	7%
Ash content	19.5%
Ultimate Analysis	
C	85.5%
H	5.2%
O	6.9%
N	1.4%
S	1%

6.2 Biomass Feedstock Selection

The biomass chosen to burn in Unit 1 and to carry this technology implementation study is hardwood pellets. The selection of pellets over other biomass products relates to the multiple technical advantages offered (see Section 5), namely the maturity of their production technology and the security provided by a well-established market. Moreover, operational experience shows that the use of virgin wood biomass results in longer periods between downtimes for boiler cleaning. In contrast, demolition wood has proved to be problematic due to the chemical treatment that it may have gone through, reducing the intervals for cleaning. What is more, virgin wood biomass might present better environmental performance, when it comes to the release of pollutants such as SO_x, mercury and dioxins (Fossum, 2010).

The Energy Research Centre of the Netherlands (ECN) has built an extensive online database for biomass and waste. From there, hardwood pellets from Estonia were selected due to the completeness of their chemical analysis, fundamental for the present study. Table 5 presents a summary of the properties of the chosen biomass product.

Table 5. Hardwood Pellets Properties (ECN, 2012)

HHV (a.r)	20.24 MJ/kg
LHV (a.r)	16.22 MJ/kg
Proximate analysis	
Moisture content	9%
Ash content	0.4%
Ultimate Analysis	
C	51.02%
H	7.54%
O	41.85%
N	0.03%
S	0%

6.3. Initial Considerations for the Full Conversion of Unit 1 to Biomass

The key for making full-biomass conversion an attractive alternative is keeping investment costs within reasonable limits. It is safe to assume that investment costs have a strong relation to the scale of the modifications and/or additions necessary for Unit 1 to run exclusively on biomass. With this idea in mind, it is possible to define certain aspects that will strongly influence the calculation model and the results it delivers.

On the one hand, several technical aspects of Unit 1 will remain unchanged. For instance,

pulverized fuel is kept as the combustion technology in order to increase the reuse value of the existing equipment. Despite a number of positive experiences in the conversion from PFC to BFB observed in Poland, Schaaf *et al.* (2010) affirm that fitting new/modified equipment on an existing facility is a very challenging task, due to space restrictions and interferences. Moreover, the temperature profile of the working fluid will be kept the same to maximize efficiency and to take advantage of the materials and pressure rating of equipment such as heat exchangers and steam turbine. Also, the steam/water circuit will suffer no modifications, preserving features like sootblowing, attemperation and blowdown. Finally, as described in Section 5, pellet size is going to be reduced back to dust in the existing coal mills. After that, wood dust will enter the furnace at the same proportion as coal dust used to be injected, at a rate of 12.08 kg/s. Nevertheless, the lower density of pellets will represent a higher volume of fuel entering the furnace, hence requiring the modification of the fuel delivery system.

On the other hand, some parameters have to be adjusted to meet the requirements associated with biomass combustion. In the first place, preheated air temperature was reduced to 90 °C in an attempt to minimize the risk of self-ignition in the pulverizers. Nevertheless, forecasting the interaction of dry air and biomass is a challenging task due to variation in particle size, the kind of material and the fuel composition. Van Loo & Koppejan (2010) declare that once biomass fuel reaches temperatures beyond 105 °C, it acquires a high tendency to self-ignite. For this reason, a safety margin is considered. Secondly, a smaller air preheating demand generates a steeper flue gas versus heat load curve, causing conflicts with the pinch point. According to the conditions established for Unit 1, the pinch point is located between the economizer inlet and the flue gas flowing in that section of the boiler. The furnace outlet temperature was set at 240 °C to keep a pinch point of approximately 45 °C. Thirdly, furnace exit gas temperature (FEGT) is set at 1100 °C. Despite the fact that initial ash deformation temperature for hardwood is approximately 1150 °C (*ibid*), Rayaprolu (2009) indicates that gas temperatures at the end of the furnace must be at least 55 °C below the deformation temperature to prevent fouling and slagging problems. Lastly, the steam mass flow was adjusted using an iterative process until the model satisfied most, if not all, initial conditions.

6.4. Results

In the following section, a summary of the results obtained using the calculation model is presented. Efforts are made to show the most relevant technical parameters of Unit 1 operating

as business as usual (coal combustion). In addition, this data is compared against the results for biomass combustion. The ultimate goal of comparisons is to provide a better understanding of the effects on performance and boiler operation derived from the shift to biomass.

Maintaining the water/steam temperature profile and pressure has a major significance for the conversion of Unit 1 to biomass. An alteration in the boiler's energy balance is expected as a result of the use of a fuel with lower energy content. As it can be observed in Figure 16, the profile described by biomass combustion clearly differs from the one presented by coal combustion. In the first place, biomass combustion features a lower furnace inlet temperature. In contrast, it produces a significantly higher boiler exit temperature. Moreover, the smaller air preheating requirement of biomass combustion causes a slight alteration in the heat load distribution for all the different heat exchangers. Lastly, a common element observed in the FG curves for both fuels, is the constant temperature profile described by flue gases in the evaporator.

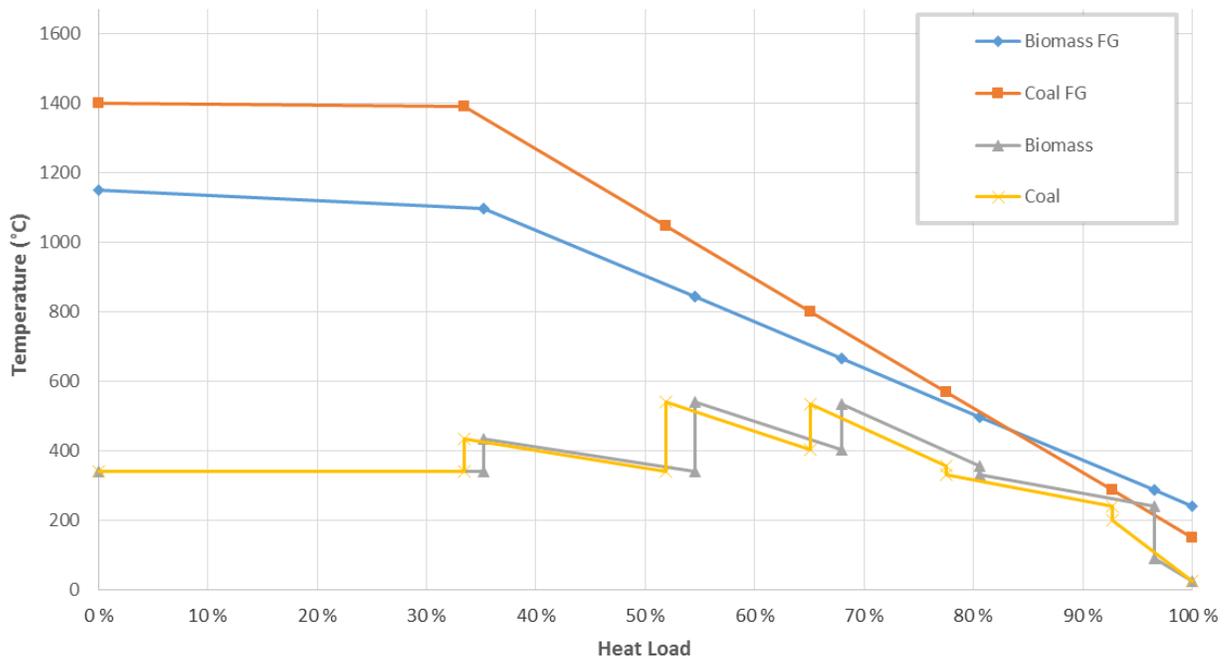


Figure 16. Temperature profile for coal and biomass

Figure 17 shows a comparison of the actual heat load values for all heat recovery equipment in Unit 1. Evidently, biomass combustion presents significantly lower heat absorption. According to the results obtained using the calculation model, the total amount of heat absorbed by

Unit 1's boiler while using coal is approximately 318 MW. Meanwhile, this amount drops to 167 MW for biomass combustion, a reduction of 48% in the production of thermal power. In addition, as it may be hinted by Figure 16, aside from the lower air preheater load, proportions in the heat load distribution are mostly unchanged.

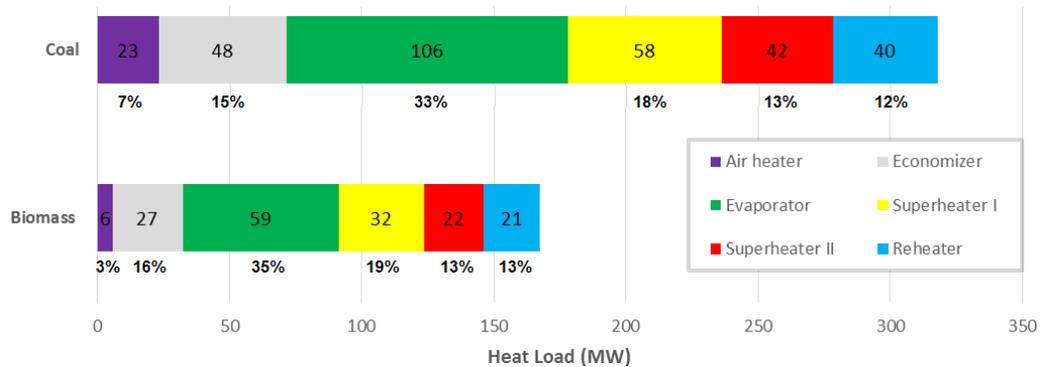


Figure 17. Comparison of heat load distribution

A contrast of the required heat exchange surface is presented in Figure 18. The necessary heat transfer area for the combustion of hardwood pellets is evidently inferior to the surface available in Unit 1. The economizer section features the greater discrepancy in area requirement with 34.2%, followed by the first superheater with 27.9%. On the other hand, the reheater comes close to utilizing all its available heat exchange area, with a disparity of only 11.6%.

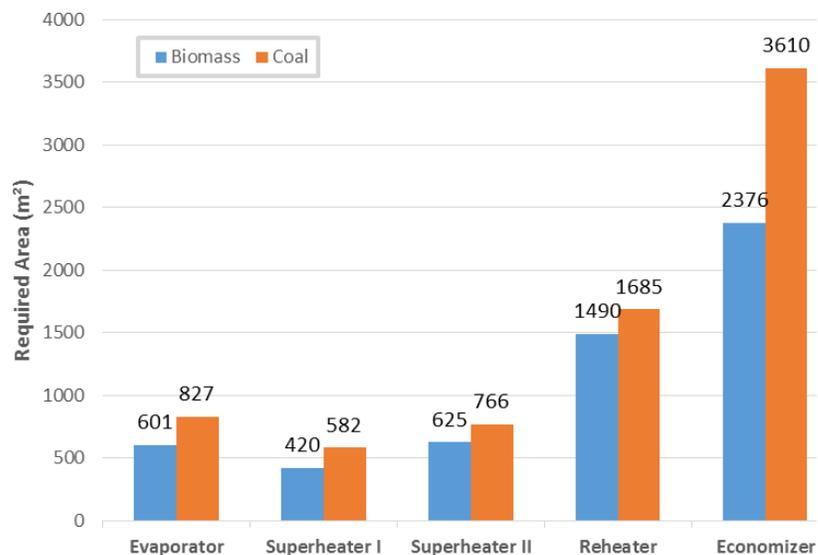


Figure 18. Required heat transfer area

Finally, technical parameters such as electric power and the measure of boiler efficiency are essential for the technical evaluation of a generating station. Even more, people with little background in power generation may consider these two parameters as the only relevant information concerning Unit 1. As presented in Figure 19, coal combustion leads in both electrical output and efficiency, with 110 MW and 84.8%, respectively. Biomass combustion comes second, delivering 58.6 MW of electrical power and operating at 72.4% efficiency.

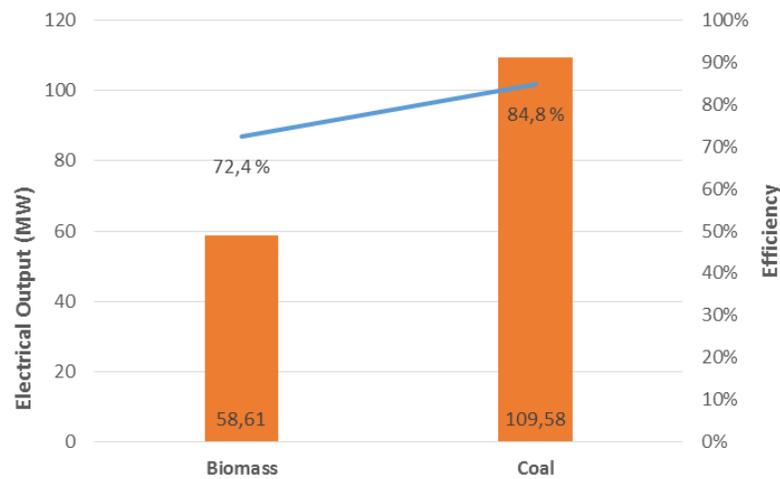


Figure 19. Comparison of electrical output and efficiency

6.5. Discussion

It has been made clear that an essential item to consider in steam generator design is the fuel to be utilized. Key parameters such as fuel treatment, size and location of heat exchangers, ash removal devices and flue gas treatment technology depend greatly on fuel characteristics. In the case of PFC coal boilers, large furnaces are required to ensure the complete combustion of solid fuel particles. Furthermore, the installation of attemperation, blowdown and sootblowing devices increases the boiler size and adds to the operation costs. Singer (1991) affirms that the lower the coal grade, the larger the required furnace size to ensure unproblematic operation. In this context, a high-grade coal such as the half anthracite used in Vojany I Unit 1 might reduce fuel-related downtime due to its favorable characteristics. Also, half anthracite may demand a small heat exchange surface due to its good ash behavior.

An important factor for selecting pellets as fuel for Unit 1 was the capability to allow the reuse of existing equipment. Size reduction of fuel in Unit 1 takes place prior to the entrance to the boiler in two drum ball coal mills. According to Livingston (2013), this equipment may reduce

pellets back to dust, causing little to no impact on the regular operation. On the other hand, biomass fuels other than pellets may cause issues in the existing coal mills. Use of cheaper fuels, such as wood chips, may require the installation of specialized size reduction equipment. Besides, design of coal pulverizers is based on the brittle fracture mechanism; meanwhile, abrasion fracture is the predominant mechanism for size reduction of biomass (Obenberger & Thek, 2010). After multiple successful experiences in Europe, hammer mills have proven to be best suited for this task.

Heat load distribution remains largely undisturbed as a consequence of the conservation of the steam temperature profile. Maintaining a similar profile for the working fluid was deemed necessary to make better use of the existing equipment. Pipework, valves, the steam turbine, among other equipment, were installed to deliver cost-effective performance when operating under design conditions. In this regard, adopting a different set of conditions for the working fluid, while permissible by Unit 1's boiler design, might incur a misuse of assets. Moreover, heat load distribution for exchangers matches typical values for electrical utilities: the greatest amount of heat absorption takes place in the evaporator section with approximately 30% of the heat load, followed by the superheaters, with a combined load of 35% (Stultz & Kitto, 2005). Moreover, the divergence in heat load distribution obeys a lower air preheating requirement for biomass combustion. Finally, as a consequence of keeping the water/steam temperature profile and pressure unmodified, the enthalpy drop for steam in both high and low pressure sections of the turbine will remain constant. However, electrical output is directly proportional to the mass flow of the working fluid. Accordingly, an important reduction in the installed capacity is experienced in Unit 1 when hardwood pellets are used as fuel.

A significant drop in boiler efficiency is observed for biomass combustion. This parameter provides an indication of the efficacy of heat transfer by the account of energy inputs and outputs. The main discrepancy in the energy balance during the firing of biomass relates to the decrease of heat load and the lower calorific value of the fuel. Furthermore, energy input coming from preheated air is also reduced. As it has been discussed previously, the decrease of energy from preheated air complies with safety precautions. It is important that air used to transport fuel from the pulverizers all the way to the burners is cold enough to minimize biomass self-ignition hazard. On the other hand, energy loss due to blowdown regime is lowered. Nevertheless, blowdown plays a small part in the energy balance, thus its variation may not greatly affect

the results for efficiency.

Coal is commonly defined as organic material that has been exposed to high pressure and high temperature for extended periods of time. Therefore, it is not farfetched to consider hardwood pellets to behave similarly to low grade coal. The logical conclusion would be that the combustion of biomass in Unit 1 makes necessary a larger area to deliver the same heat output due to lower energy content and poor ash characteristics. Nevertheless, this may not be reflected in the results introduced previously, as a consequence of the reduction in steam/water mass flow. The reduction of steam mass flow relates to an iterative process performed to determine a set of conditions that may reconcile FG temperature, efficiency and required area for heat exchange, within acceptable values. Specifically, the mass flow rate of circulating fluid is reduced to produce an adequate flue gas temperature profile that provides sufficient cooling before leaving the boiler. The distinctive chemistry of biomass is largely responsible for the inferior temperatures in the furnace.

The heat transfer area, represented as tube walls and as heat exchangers, depends on the working fluid and flue gas conditions, boiler configuration and fuel properties. Heat load is directly proportional to the mass of steam/water circulating in the boiler. Accordingly, reduction of the steam mass flow represents a significant decrease in the total heat load. In the present case, reducing the flow of working fluid decreases the area required for heat transfer. Also, reduced heat load may translate into lower flue gas temperatures. Simultaneously, lower flue gas temperatures diminish the LMTD. As a result, heat transfer resistance increases and the heat exchange surface required for biomass combustion in Unit 1 is smaller than it would normally require when burning coal. This does not necessarily mean that modifications are required to reduce the area of the heat exchangers, but simply implies that available heat transfer area is greater than required for biomass combustion, according to the conditions and limitations previously mentioned.

Combustion in PFC boilers is a transient process, meaning that the release of heat is not instantaneous, but rather a gradual progression. Regardless of the fact that combustion is a well-understood process, the numerous factors involved make its accurate calculation challenging. Assuming that the heat load of the heat recovery equipment is equivalent to the heat loss of the flue gas may not be completely accurate. Nevertheless, this approach provides a good

picture of how flue gas temperature fluctuates on the path from its origin in the furnace, all the way to the boiler exit, after the air preheater. For the most part, flue gas temperature profile falls within the expected behavior described by Rayaprolu (2009). Gases reaching the back-pass section of the boiler display a typical temperature between 500 and 600 °C. However, the high furnace temperature witnessed in biomass combustion may cause ash-related issues in the boiler. In addition, high boiler exit temperatures may prove problematic for the equipment installed downstream of the gas path.

Ash-related issues in biomass firing are commonly related to the formation of ash deposits on the different heat exchange sections of the boiler. Also, accelerated gas-side corrosion rates and erosion are also reasons for concern. Biomass combustion introduces significant changes to the chemistry of the ash material accumulated on boiler surfaces, causing a significant impact on the interaction between metal and ash deposit. The incidence of these formations is mostly linked to chlorine, alkali and ash contents of the fuel, where hardwood may present a low tendency in this regard (Van Loo & Koppejan, 2008). As seen in numerous biomass combustion trials around Europe, the accumulation of ash has a detrimental effect on boiler O&M. Material deposits have the potential to hinder heat absorption, block the flue gas flow, to cause pipe overheating and to increase heat losses (Stultz & Kitto, 2005). Therefore, increasing the frequency of sootblowing becomes a priority. Also, it has been found that in some cases downtimes for manual cleaning of the boiler are required to ensure an adequate operation. Van Loo & Koppejan (2008) indicate that slag formation in the radiative section of the boiler occurs at temperatures in excess of 1000 °C in a matter of hours. On the other hand, deposits in the convective section, also called fouling, are formed as result of a much slower process which can take days. It takes place at temperatures close to 800 °C on the back pass of the boiler. Even though furnace outlet temperature below the initial deformation for hardwood ashes is considered, observing the flue gas temperature profile described by biomass combustion, it is evident that the gases exceed the aforementioned limits. More specifically, the average temperatures for the evaporator and both superheaters are above recommended values. Thus, slagging and fouling issues are bound to happen in Unit 1. Nevertheless, the complex nature of ash interactions is hard to predict. For this reason, numerous if not all biomass firing and co-firing projects involve a trial phase. The main goal of trials is to assess the viability of the project based on real data. They also aim to make a fine-tuning of the operation.

Current standards for the use of fly ash in the cement and concrete industry contemplate the utilization of combined coal and biomass ashes in a proportion up to 1:4, respectively (van Eijk, et al., 2012). Studies of potential applications for 100% biomass ashes are still on course. Moreover, further changes in technical standards and legislation are needed to regulate their use. Accordingly, the elimination of a source of income may constitute an argument against the conversion of Unit 1 to biomass.

Despite the biomass chemistry and the careful study of the reactions occurring in the furnace falling outside the scope of the present work, it is imperative to include in this discussion the effects of biomass combustion on pollutant emissions. Next, general estimations are provided based on a literature search. In addition, experiences with biomass co-firing can also be extrapolated. Typically, biomass fuels feature low sulfur contents. In the case of the selected fuel, hardwood pellets, the concentration of sulfur is negligible. For this reason, it is anticipated that biomass combustion may represent a major reduction in the release of sulfur oxides. Similarly, the low nitrogen content of biomass fuel and the lower combustion temperatures are expected to result in an important cut in NO_x emissions. Additionally, the greater volatiles content has the potential to create larger fuel regions thus enhancing the performance of low-NO_x burners (Van Loo & Koppejan, 2008). Moreover, there is no general consensus concerning the emission of particulate material products related to the use of biomass fuels. Some experiences indicate a major reduction in particulate emissions, while others show a considerable increase of these pollutants (ibid). It may be concluded that the release of particulate material is highly dependent on the performance of the installed pollution abatement equipment. Furthermore, the absence of traceable amounts of chlorine in the chosen fuel eliminates the chlorine input to the boiler. Therefore, HCl emissions are expected to plummet. Lastly, regarding emission levels of CO and organic pollutants, the combustion process plays a key role. A correct balance of particle size, moisture content of the fuel and proper operation might lead to emissions no higher than base levels.

In the same way, general recommendations can be provided for the devices intended for the control or air pollution. In the first instance, Van Loo & Koppejan (2008) affirm that the impact of biomass combustion on low-NO_x burners is likely to be small, some modifications to the operation provided. Ash deposition on the burners may be considered the most prominent area of risk, due to potential interference with fuel/air injection. This issue is also closely related to

the chemistry of biomass ash, mainly to the deformation temperature. On the other hand, Van Loo & Koppejan (2008) also admit that performance of secondary measures for the control of nitrogen oxides, such as SCR, are susceptible to fuel shift. Performance of the denitrification system is largely dependent on catalyst activity and its replacement rate. High concentrations of alkali metals and phosphate condensation in FGs commonly observed as product of biomass combustion may increase the incidence of catalyst poisoning. Hence, making it necessary to increase the frequency of replacement of catalyst material, while diminishing the cost effectiveness of the process. Secondly, as it has been discussed previously, the selected biomass fuel contains negligible traces of sulfur. This constitutes a strong argument to consider the deactivation of the desulfurizing reactor installed in Unit 1, as a measure to reduce the operation costs. Finally, most often proximate analysis shows that biomass fuels possess a low ash content. Ideally, this would result in a decrease of fly-ash production. However, both chemical and physical characteristics of ash may differ greatly from coal. These characteristics are of special relevance for the correct operation of the ESP. The greater concentration of submicron particles in the solid products of biomass combustion might hinder the collection efficiency (Van Loo & Koppejan, 2008).

6.6. Proposed Modifications for Vojany I Unit 1

Numerous trials with co-firing of biomass and coal have rendered valuable lessons concerning the use of the former on an industrial scale. While on paper the existing infrastructure intended for the use of coal as fuel is capable of accepting biomass, documented experiences demonstrate that certain modifications are deemed necessary to ensure a balance between safety, reliability and efficiency. Of special mention is the risk associated to the emission of fugitive dust when handling biomass fuels, which is known to have caused grievous incidents involving fires and explosions.

A series of common elements can be identified from successful experiences with biomass firing regarding the necessary plant modifications. In the first place, regardless of the chosen means of fuel delivery to the plant, vehicle access needs to be adapted to minimize dust emissions (Colechin, 2005). Secondly, an unloading area has to be designated, fitted with the means to convey the fuel to a buffer area (ibid). Thirdly, storage space provides protection from the elements and holds enough fuel to secure a continuous operation (Van Loo & Koppejan, 2008).

Fourthly, handling equipment delivers biomass to the boiler according to demand. Lastly, components that may not be so visible, however essential for a correct operation, such as instrumentation and control, power supply and maintenance routines are needed (Colechin, 2005). In addition, some optional components are also found. First, fuel preprocessing may be necessary to fit the boiler requirements for particle size, humidity, energy content, etcetera. In this sense, biomass drying and size reduction appear to be the most popular approaches. Secondly, Colechin (2005) suggests the modification of the means to inject fuel into the boiler in order to ensure optimal combustion performance. At this point, it is evident that all the reformations mentioned above can take many forms; hence, an appropriate formulation is very site specific.

Presently, Power Plant Vojany counts with a coal supply system designed to feed the twelve different units of the generating station. Therefore, for the sake of simplicity, it will be assumed henceforth that the entirety of the systems dedicated to the reception, storage and transport of fuel are meant exclusively for Unit 1.

6.6.1. Delivery and reception

Fuel arrives to Vojany I by train in a set of wagons with 65 ton capacity; subsequently, coal is unloaded by a rotary tilter. Provided that adjustments are made on the biomass supplier end, Unit 1's conversion project may benefit from this high-capacity transport system. However, experience with co-firing in the UK indicates that tipping biomass has a tendency to create dust clouds (Colechin, 2005). To counter this issue, two techniques for the control of dust have been proven effective. One of them is the confinement of the unloading area, installation of curtains and dust extraction systems. The other one involves the use of a mist system to catch fugitive particles. However, given the characteristics of Vojany I, following a similar approach to the one used in Tilbury B Power Station (See Section 5) might be more adequate. This approach incorporates the installation of a vacuum unloader and an elutriator.

6.6.2. Biomass handling

Popular methods of biomass bulk handling include screw and belt conveyors. Nevertheless, the different densities, particle sizes and size distribution featured by biomass fuels imply a series of considerations to ensure an appropriate fuel flow. Accordingly, comprehensive knowledge of the fuel characteristics is fundamental.

Co-firing trials in the UK demonstrated that the use of existing conveyor belts and chutes may be problematic due to material spillage and dust generation (Colechin, 2005). These difficulties can be lessened with minor upgrades such as the addition of enclosures and the installation of skirting between chute and conveyor. Still, dust extraction remains the most effective technique to minimize dust clouds.

6.6.3.Storage

Long term storage of biomass is deemed inappropriate in most cases due to the deterioration in the physical quality and the inherent health and safety hazards (Livingston, 2010). Generally, installed biomass-fired stations possess sufficient storage for seven days of continuous operation (Colechin, 2005). Storage methods include covered piles, enclosed bunkers and silos. The choice of the most suitable method is dictated mainly by the biomass characteristics, site conditions and frequency of fuel delivery.

Despite the high capacity offered by enclosed warehouses, these are best suited for storage at maritime ports (Obenberger & Thek, 2010). The tight building layout on Vojany I might benefit from the use of silos, more specifically, vertical silos with hopper bottoms. This type of storage maximizes holding volume and offers discharge efficiency. Moreover, silos can be grouped together with a shared loading overhead conveyor. It should be noted that confinement of biomass requires a permanent monitoring of temperature. Additionally, ancillary equipment must comply with codes for explosion hazard.

6.6.4.Fuel preprocessing

Fuel preprocessing includes a series of techniques devised to improve the quality of the fuel prior to its utilization in the furnace. Also, preprocessing aims to reconcile the characteristics of the fuel with the requirements posed by the existing systems. On the one hand, high moisture content in the fuel has the potential to hinder the efficiency of the combustion process. Depending on the type of biomass used, multiple drying options are made available. Yet, little experience is found for large-scale systems (Colechin, 2005). Nevertheless, it may be argued that the hardwood pellets used in Unit 1 have relatively low moisture content. For this reason, the drying of biomass is deemed unnecessary. On the other hand, experiences in Northern Europe demonstrate that processing of wood pellets in conventional coal mills is feasible. Minimal size

reduction takes place in the mill, but provided an adequate particle size distribution of the sawdust, an optimal combustion can be achieved (Van Loo & Koppejan, 2008). Even so, experience with wood pellet pulverization at Ironbridge B Power Station demonstrates that hammer mills are better suited for this task due to the improvement in material throughput (SECTOR, 2012). In general terms, the required main modifications to the mills are the reduction of primary air temperature to prevent the spontaneous combustion of biomass; adjustment of the control systems to handle fuel with lower density and the installation of explosion detection and suppression systems.

6.6.5. Burners

Combustors are designed to inject fuel into the furnace in the most efficient way possible. At the same time, these devices allow a correct and reliable operation. After examining related literature, it is evident that there is still limited experience with the reuse and adjustment of conventional burners to fire biomass fuels in large utility boilers (Colechin, 2005; Obenberger & Thek, 2010; Van Loo & Koppejan, 2008). Even so, lessons learnt from co-firing practice reveal that with appropriate modifications an acceptable trouble-free operation can be achieved (Obenberger & Thek, 2010). These modifications are not only costly, but they also may result in considerable operational problems when poorly formulated (Livingston, 2010). Accordingly, any modifications must be subject to careful inspection and exhaustive risk assessment. Another approach to biomass combustion is the installation of purpose-built burners (Obenberger & Thek, 2010). It may be concluded that fuel properties, existing physical constraints of the plant and performance requirements will play a major role in the determination of the combustion technology.

Based on the ongoing positive technical experience exhibited at Atikokan Generating Station (see Section 5), added to the assumption that conversion of Unit 1 to biomass is intended for the long-term, the installation of purpose-built burners may be a better option. The installation of new, specialized combustors is likely to reduce the risk associated with inadequately implemented modifications. In addition, the use of different materials and adjusted geometry of purpose-built burners might provide an acceptable combustion behavior and lower incidence of downtimes for maintenance.

Table 6 presents a summary of the modifications/additions deemed necessary for Vojany I Unit

1 to ensure a correct balance between safety, reliability and performance.

Table 6. Summary of recommended modifications/additions to Vojany I

Delivery and Reception	Installation of a vacuum unloader system and elutriator
Biomass handling	Modification of conveyors belts (installation of curtains, speed adjustment), modification of hoper angles
Storage	Installation of 2 x 7,000 t capacity silos fitted with temperature monitoring and fire suppression system
Fuel preprocessing	Reduction of air temperature, adjustment of the control system, installation of fire suppression and explosion prevention systems
Fuel injection	Installation of purpose-built biomass burners

Lastly, Figure 20 shows a graphical depiction of the modifications and/or additions recommended for the conversion of Vojany I Unit 1 to biomass. It should be noted that Figure 20 is a fairly accurately scaled representation of Vojany I; however, some liberties have been taken in the dimensioning of additional components.

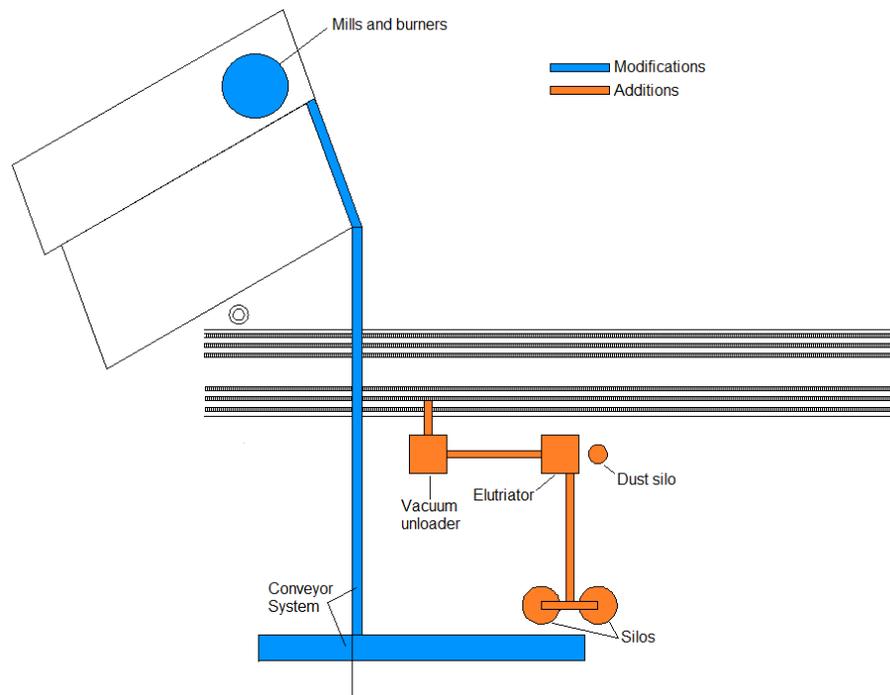


Figure 20. Additions/Modifications to Vojany I

7. EVALUATION OF ECONOMIC FEASIBILITY

It is fair to say that renewable energy has reached a more mature status in recent years as a result of continuous efforts in R&D. Nonetheless, the lack of accurate information concerning costs makes it difficult for stakeholders and policy makers to consider these technologies as a viable alternative to fossil fuel-based power generation. The present section aims to fill a gap in this regard for the conversion to biomass of existing coal-fired plants. Once more, Vojany I Unit 1 is utilized as a base case for study. It should be noted that the present is not a detailed financial analysis of project economics and only very general cost estimations are provided. Nevertheless, efforts are made to obtain reliable and updated information in accordance with the conditions posed by Unit 1, to evaluate the costs of the proposed technology. Accordingly, resulting data is intended to promote debate about the feasibility of conversion to biomass. Subsequent studies should focus on the dissection of the numerous aspects driving the costs of power plant conversion. The acquisition of accurate cost estimates may be a valuable tool for the involved parties to make informed decisions.

Numerous and often intertwined cost factors can make of the economic analysis of a power plant a challenging task. Moreover, the high degree of uncertainty in the formulation of the necessary additions/modifications for Unit 1 to operate with biomass hinders the elaboration of an accurate cash flow model. However, being this a general economic assessment, a simplified approach is favored. This section examines the fixed and variable cost components of conversion to biomass and provides the Levelized Cost of Electricity (LCOE), according to a set of assumptions. In simple terms, LCOE yields the price that a project must earn per megawatt hour in order to break even (Salvatore, 2013). LCOE encompasses all the associated costs of producing power during the lifetime of the project, namely the initial investment, O&M, cost of fuel and cost of capital (NREL, 2014). Estimation of LCOE allows suitable comparisons among the proposed technology and coal firing. For the calculation of the simplified LCOE, the following formula is used (ibid):

$$sLCOE = \frac{[(Capital\ cost * CRF) + Fixed\ O\&M\ Cost]}{8760 * Capacity\ factor} + (Fuel\ cost * Heat\ rate) + Variable\ O\&M$$

CRF stands for Capital Recovery factor, where i represents interest rate and n the number of annuities received.

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

7.1. Key Assumptions

Firstly, economic life of coal plants is relatively long, approximately 20 years, according to Rhyne and Klein (2014). Once the initial investment has been recovered, a conventional power plant may continue to operate for 5 to 15 years more before requiring additional investment. Some operators opt for plant decommissioning, while others engage in repowering initiatives to extend the plant's life. Similarly, it is estimated that economic life of biomass plants range from 20 to 25 years (IRENA, 2012).

Unit 1 is assumed to generate usable power in a rate similar to a conventional coal-fired plant. Ortiz *et al.* (2011) and IRENA (2012) agree that biomass-fired power plants can operate at an 85% capacity factor. Nevertheless, power generation is closely related to plant design and biomass availability.

Fuel cost is a major component of the cost of generation. Generally, prices for biomass fuels are driven by the distance to the source and plant design (Rhyne & Klein, 2014). Other factors affecting the cost of fuel are market conditions and fuel specifications. Therefore, fuel cost represents a significant source of uncertainty for the economic evaluation of the conversion of Vojany I Unit 1. References differ widely about the cost of wood pellets. Ortiz *et al.* (2011) and EPA (2007) report prices as low as 2 USD per GJ; however, these prices are seemingly valid under the American context. Moreover, IRENA (2012) presents a value for wood pellets of 9 USD/GJ, including transportation. The last estimation is deemed to work better in this economic analysis due to the globally-oriented character of the International Renewable Energy Agency.

Since Unit 1's conversion to biomass is performed over brownfield, capital costs only take into account those associated with the addition/modification of equipment to facilitate the reception, storage, handling and processing of biomass. As a consequence, capital costs are deemed to

be highly case sensitive for conversion to biomass projects. In this regard, literature offers limited references. However, IRENA (2012) presents an estimation of 900-1500 USD per kW capital expenditure for 100% biomass repowering projects. In addition, a cancelled retrofit project at Burger plant (USA) in 2010 concluded that the capital costs of conversion were about 700 USD/kW.

O&M refers to the fixed and variable costs associated with the operation and maintenance of Unit 1. In the first place, fixed O&M costs correspond to costs originated regardless of the actual plant operation. For example, labor, insurance, scheduled maintenance, routine component replacement, etcetera (Rhyne & Klein, 2014). On the contrary, variable O&M costs depend on the number of hours a power plant operates and its size. It encompasses consumables (nonfuel products), ash disposal, unplanned maintenance, water supply, etcetera (IRENA, 2012). Once again, data for O&M vary greatly from case to case. Often, references display a combined value for variable and fixed O&M, hindering their appropriate discerning. Such is the case for biomass firing plants in Western Europe. According to Salvatore (2013), operating expenditure ranges between 90 and 200 USD per kW-year. Also, a joint report prepared by the EPRI and the U.S Department of Energy in 1997 estimates that fixed O&M cost for biomass-firing plants is 60 USD/kW-yr and variable cost can reach 0.0085 USD/kWh. Likewise, Rhyne and Klein (2014) suggest costs of 106 USD/kW-yr and 0.0053 USD/kW, respectively. The recent date of publication, added to the cost component breakdown displayed by the study performed by Rhyne and Klein, makes this data preferable.

Lastly, the definition of discount rate greatly influences the outcome of LCOE. Even so, bioenergy projects are less sensitive to this cost factor in comparison with wind solar and hydropower (IRENA, 2012). A standard value for discount rate used in this kind of projects is set at 10%.

7.2. Results for LCOE

Two scenarios were created to estimate possible costing approaches to the conversion of Unit 1. The first one, also known as conservative scenario, considers an economic life of the plant of 20 years and high capital expenditure. On the other hand, a second scenario recreates favorable conditions for the retrofit of Unit 1, with an extended economic life of the project and modest capital costs. This is designated as the optimistic scenario. Other cost components remain unchanged. Finally, it should be noted that all cost components are converted from

USD to EUR¹. Table 7 shows an account of the different cost components included in the two scenarios and the calculated value of LCOE.

Table 7. Cost Components of LCOE

Cost Component	Units	Conservative Scenario	Optimistic Scenario	Average
Capital Cost	€/kW	1,365	637	1,001
Economic Life	yr	20	25	22,5
Discount Rate	%	10 %	10 %	10 %
Capital Recovery Factor		0.1174	0.1101	0.1132
Fixed O&M Cost	€/kW-yr	96.46	96.46	96.46
Variable O&M Cost	€/kWh	0.00482	0.00482	0.00482
Capacity Factor	%	85 %	85 %	85 %
Fuel Cost	€/GJ	8.19	8.19	8.19
Heat Rate	GJ/kWh	0.01204	0.01204	0.01204
sLCOE	€/kWh	0.1379	0.1258	0.1316
	€/MWh	138	126	132

The economic evaluation of Unit 1's conversion initiative reveals that under a set of optimal conditions, the minimum wholesale price of energy required to recover the initial investment over a period of 25 years is approximately €126. This result is comparable to the figures presented by Albani *et al.* (2014), who suggest an LCOE for plants converted from coal that fluctuates from €96 to €101/MWh. Even though estimated costs for Unit 1 are visibly higher, a possible explanation for the lower costs displayed in their study is the benefit obtained thanks to economies of scale. The power plant used as a basis by Albani has a capacity of 200 MW, more than 3 times the capacity delivered by Unit 1 running on biomass. Furthermore, critical assumptions such as the cost of the fuel and capital expenditure are not disclosed in their study, reducing the grounds for comparison. Figure 21 compares the calculated LCOE for Unit 1 with equivalent technologies and studies.

¹ As of March, the 26th of 2015 the USD-EUR exchange rate is set as 0.91 euros for every dollar.

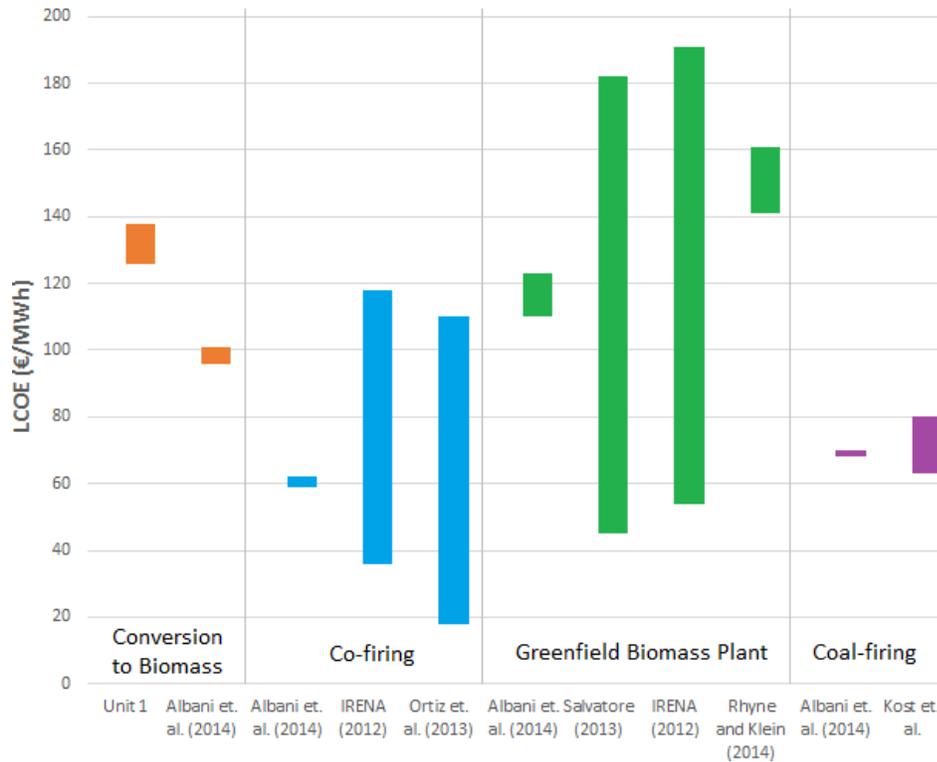


Figure 21. LCOE comparison

Bioenergy may provide competitive prices where capital costs are moderate and low-cost biomass is available. In contrast, higher investment costs and expensive fuel diminish the attractiveness of plant conversion to biomass. The creation of support policies, such as tax exemption and stimulus programs, may lessen this negative outcome. The low-cost conversion approach used for Vojany I Unit 1 may be beneficial in this regard due to the repurposing of existing systems and the high transport efficiency thanks to railroad fuel delivery. Development of a supply chain for biomass becomes a critical factor in making biomass-firing a feasible option for power generation. Still, Albani *et al.* (2014) predict a substantial decrease of almost half by 2025 in the levelized cost of energy for bioenergy as a result of a number of improvements. For example, increase in steam parameters, plant design standardization and supply chain optimization.

Another cost factor that can make a significant contribution to the LCOE is the operating expenses. Typically, these costs account for 9 to 20% of the LCOE for biomass plants (IRENA, 2012). O&M costs represent the magnitude of fuel preparation, handling and processing needed to achieve an acceptable performance. Given the scale of the additions/modifications

recommended for the conversion to biomass of Unit 1, O&M costs are expected to represent an important share of LCOE.

7.3. Additional considerations

The present document is an initial engineering feasibility analysis; hence accurate calculation of capital expenditure, fuel costs and O&M costs are outside the scope of this work. Accordingly, the figures presented previously are a rough estimation of the associated costs for conversion of Unit 1 to biomass. Further studies should account for detailed engineering of the recommended equipment additions/modifications. In addition, financing costs, derate, inflation, permits and emission credits also need to be evaluated.

Environmental mitigation measures have become, over time, more relevant to the economics of power plants. The reduction potential for tightly regulated pollutants such as nitrogen oxides and sulfur oxides offered by power plant repowering may constitute an opportunity to obtain certified emission reductions. The EU emission trading system is recovering from a severe drop in prices that started the second half of 2011 and presently, CER trade price is close to €7/tCO_{2e} (SendeCO₂, 2015). Nevertheless, with the imminent expiry of the Kyoto protocol and the Copenhagen accords by the end of the decade, it is expected that market-oriented mechanisms will be improved and integrated globally (Mansell, 2015). Thus, an eventual rise in prices might increase the economic appeal of conversion.

The cost to build and operate a power plant is derived from multiple factors, including which technology is built, plant location, financing costs and overall plant production. Moreover, costs are also affected by less visible factors such as market environment, labor and resource costs, regulatory issues and local conditions (Rhyne & Klein, 2014). Costs of financing and taxes may comprise a significant share of the cost of constructing and running a power plant. The financing scheme for any sort of power plant is unique depending on the project backing, the markets, technology type and the acquired power sale contracts. Another element to consider is the part played by financial institutions and their willingness to provide long-term loans. The cost of borrowing money is, in great part, associated to the perceived risk of the project.

8. CONCLUSIONS

The primary goal of this work is to produce clear and complete information regarding the implications, on a technical and economic level, of repowering an existing coal-fired power plant to completely shift its fuel to biomass. Whether this technology is a feasible alternative is a question without a simple answer and several factors need to be carefully examined to produce a final verdict.

Fuel properties dictate crucial aspects of power plant design. The use of wood pellets as fuel was deemed as the most favorable alternative for the conversion of Unit 1 due to transport efficiency, low moisture content, high energy content and ease for size reduction. Still, the divergent properties of the selected biomass against coal may produce significant changes in terms of performance, O&M and costing when fuel is shifted. Regardless of the fact that existing equipment can be reutilized for the most part, extensive additions/modifications may be required to ensure a safe operation and an acceptable performance. To put it simply, repowering a coal-firing plant offers renewable energy with low pollutant emissions at the cost of reduced capacity, relatively high LCOE and sometimes, a maintenance-intensive operation. Correspondingly, the adoption of this technology largely depends on the will of the plant owner to go green.

The scope of this project was ambitious; even so, efforts were made to produce a comprehensive view of the aspects involved in a conversion to a biomass-based enterprise. Nevertheless, the accurate estimation of costing factors is identified as being a key area for improvement in further studies. It is expected that the knowledge gathered in this document will deliver practical information for decision makers in the energy sector and policymakers.

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APPENDICES

1. VOJANY I UNIT 1 PFC COAL COMBUSTION

Balances

Mass and energy balances are elaborated considering steam production in a Rankine cycle with reheat. Firstly, feedwater enters the boiler with a temperature of 240 °C and flows through the economizer, where it increases its temperature. Before reaching the saturation point, preheated water proceeds to a tube wall evaporator, where the phase change takes place. After that, steam is superheated in two heat exchangers until it reaches a peak temperature and pressure of 540 °C and 13.6 MPa, respectively. Moreover, feedwater is used in the first superheater to control the steam temperature. Once the main steam expands in the high pressure stage of the turbine, it reenters the boiler at 357 °C and 3.2 MPa. A reheater adds heat to the expanded steam, in a procedure to increase the thermal efficiency of the boiler, raising its temperature to 535 °C. Later, reheated steam is directed to the low pressure stage of the turbine. On the other hand, ambient air at 25 °C, sea level pressure and relative humidity of 60% is preheated before being used in combustion. Lastly, flue gas leaving the boiler was assumed to possess a typical temperature of 150 °C (Rayaprolu, 2009). An account of the main parameters used as starting values is summarized in Table 8.

Table 8. Starting values

	In	out
Fuel LHV (MJ/kg)		24.73
Fuel flow (kg/s)		12.08
Air temperature (°C)	25	200
Feedwater temperature (°C)	240	330
Main steam temperature (°C)	540	
Reheated steam temperature (°C)	357	535
Ambient air pressure (kPa)		101.325
Drum Pressure (MPa)		14.96
Main steam pressure (MPa)		13.6
Reheated steam pressure (MPa)	3.2	3

Now that initial conditions have been established, required air for combustion and the resulting flue gases can be quantified. The amounts of air and flue gases are calculated based on ambient conditions and fuel ultimate analysis. Furthermore, these amounts are expressed as the rate of mass per kilogram of fuel.

Air Flow Rate

The theoretical amount of air necessary for combustion is determined according to the fuel ultimate analysis. One kilogram of fuel on arrival conditions is considered as the basis. In addition, complete combustion is assumed. The air demand, more specifically oxygen demand, is estimated based to the following combustion reactions:

$C + O_2 \rightarrow CO_2$	(1)
$2H + \frac{1}{2} O_2 \rightarrow H_2O$	(2)
$S + O_2 \rightarrow SO_2$	(3)

Some additional considerations are the assumption that no nitrogen oxides are produced during the reactions and all sulfur is oxidized as SO_2 . In addition, chlorine is considered negligible. Also fuel-bound oxygen is assumed to form O_2 , hence contributing to the oxygen demand of combustion. Table 9 shows the results for stoichiometric oxygen demand per kilogram of fuel.

Table 9. Theoretical oxygen demand

Element	Dry ash free	Mass (kg)	MM (kg/kmol)	N (kmol)	O2 (kmol)
C	85.50%	0.6759	12	0.056	0.0563
H	5.20%	0.0411	1	0.041	0.0102
O	6.90%	0.0545	16	0.003	-0.0017
N	1.40%	0.0111	14	0.001	-
S	1.00%	0.0079	32	0.000	0.0002
Cl	0.00%	0.0000	35	0.000	-
H2O	7.00%	0.0553	18	0.003	-
Ash	19.50%	0.1542	-	-	-
Total	126.50%	1.000	128.550	0.105	0.06501

As previously stated, air enters the boiler at ambient conditions. Moisture content of air is calculated based on the relative humidity, following equation 4.

$RH = \frac{P_{H_2O}}{P_{Sat}}$	(4)
---------------------------------	-----

Where P_{H_2O} corresponds to partial pressure of water in ambient air and P_{sat} is the saturation pressure at 25 °C, read from water/steam tables. Hence, solving for P_{H_2O} :

$$P_{H_2O} = P_{Sat} * RH = 3,170 \text{ Pa} * 0.6 = 1,902 \text{ Pa}$$

According to Raoult's law, the water molar fraction (y_{H_2O}) in the air is equivalent to the ratio between the water partial pressure and the atmospheric pressure (P_{atm}), as presented on equation 5.

$$y_{H_2O} = \frac{P_{H_2O}}{P_{atm}} = \frac{1,902 \text{ Pa}}{101,325 \text{ Pa}} = 0.0188 \quad (5)$$

Dry air is assumed to contain 21% oxygen and 79% nitrogen. The wet basis fractions of O_2 and N_2 are calculated considering that for every mole of dry air, there is 0.0188 moles of water.

$$O_2(\%mol, wet air) = \frac{0.21}{1 + 0.0188} = 20.61\%$$

A typical value of excess air for PFC boilers is set at 20%. This means that the amount of air used for combustion is 1.2 times higher to stoichiometric levels. Calculations for amount of air per kilogram of fuel are presented in Table 10.

Table 10. Combustion air demand

Component	Composition	N (kmol/kg fuel)	Mass (kg/kg fuel)
H ₂ O	1.88%	0.007	0.13
O ₂	20.61%	0.078	2.50
N ₂	77.54%	0.293	8.22
Total Air (wet)	100%	0.378	10.84
Total Air (dry)	-	0.371	10.72

Flue Gas Flow Rate

The flue gas flow rate is also determined by the fuel ultimate analysis and the previously described chemical reactions taking place during combustion. It should be noted that the presence of moisture in flue gas is originated from the sum of water present in both fuel and air, and water product of combustion reactions. Similarly, the occurrence of nitrogen in flue gases corresponds to fuel-bound nitrogen and nitrogen from combustion air. Finally, a small fraction of oxygen is not utilized due to the presence of excess air. Table 11 shows the results for amounts and composition of flue gas.

Table 11. Flue gas production

Component	N (kmol/kg fuel)	%	Mass (kg/kg fuel)
CO ₂	0.056	14.3%	2.48
H ₂ O	0.031	7.8%	0.55
SO ₂	0.000	0.1%	0.02
N ₂	0.294	74.6%	8.23
O ₂	0.013	3.3%	0.42
Total flue gas (wet)	0.394	100.0%	11.69
Total flue gas (dry)	0.363		11.14

Steam and Feedwater Flow Rate

Main steam leaves the second superheater at 540 °C and 13.6 MPa, at a rate of 97.22 kg/s and an equivalent amount of steam is assumed to reenter the boiler for reheating. Normally, utility boilers such as Unit 1 include blowdown and sootblowing. The former prevents mineral build-ups in the pipework by purging the impurities accumulated within the steam drum. Raya-prolu (2009) recommends purging 3% of the water entering the drum. On the other hand, sootblowing involves the utilization of a number of nozzles distributed along the boiler. These nozzles produce jets of high pressure, high temperature steam used to clean the heat transfer surfaces. Since PFC boilers have a high slagging and fouling tendency, Rayaprolu (2009) also suggests the installation of multiple sootblowing ports across the boiler, delivering steam at a rate of 4.16 kg/s. Finally, feedwater is injected into the main steam to control its outlet temperature. This technique, called attemperation, was set at 4%. Figure 22 shows the mass flows for the working fluid on Unit 1.

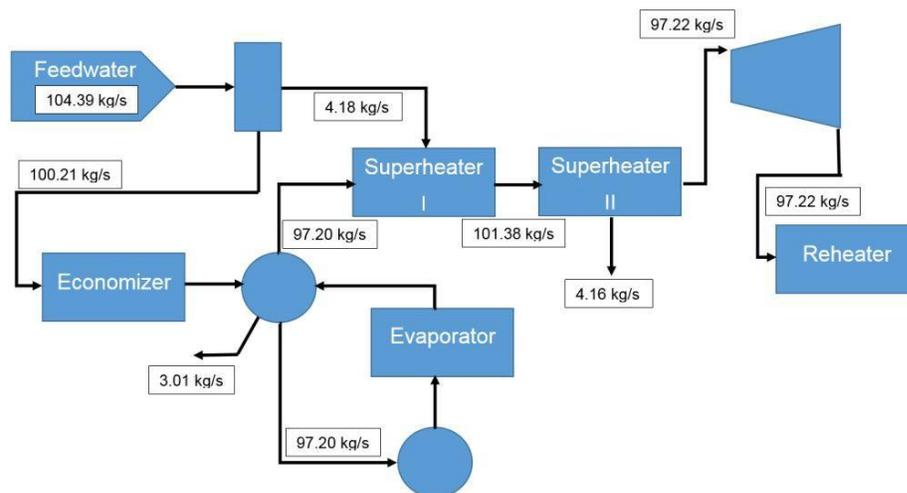


Figure 22. Feedwater/steam mass flows

Steam/Water Conditions

The conditions of the working fluid across the different sections of the boiler can be established based on the starting values, the use of steam tables and making some basic assumptions. First, Rayaprolu (2009) indicates that typically the pressure drop in the superheater is 8%. Similarly, the economizer experiences a drop in pressure close to 0.3 MPa. Secondly, two superheaters with attemperation have been included. In this case, ibid recommends a temperature drop of 30°C. The use of an iterative process is necessary to determine the temperature drop between the first and the second superheater. Thirdly, no temperature increase takes place in the evaporator. The temperature throughout the evaporator will be equal to the saturation temperature for a pressure of 14.7 MPa. Nevertheless, a safety margin or terminal temperature difference of the water at the economizer outlet of 10 °C is set to avoid evaporation inside the economizer. Therefore, the economizer outlet temperature is equal to the saturation temperature minus ten degrees. Once temperatures and pressures are known for each section of the boiler, enthalpies can be read from steam tables and heat loads for each heat exchanger can also be calculated, according to equation 6 and 7.

$Q = \dot{m} * (h_{out} - h_{in})$	(6)
$Q = \dot{m} * C_p * (T_{out} - T_{in})$	(7)

Where Q represents the heat load; \dot{m} is the mass flow and h_{out} and h_{in} are the enthalpy at the outlet and the inlet of the heat exchanger, respectively. Also, C_p is the fluid specific heat and T_{out} and T_{in} are the temperature at the outlet and the inlet of the heat exchanger, respectively.

It should be noted that the steam in the first superheater experiences an enthalpy increase product of attemperation by feedwater spraying. In contrast, the evaporator heat load accounts for the blowdown requirement. In the same way, the sootblowing requirement reduces the heat load on the second superheater. In the case of the air preheater, the energy absorbed is directly estimated by the heat capacity at mean temperature, making use of equation 7. Results for temperature, pressure, enthalpy and heat load can be seen in Table 12.

Table 12. Steam/water conditions

Steam/Water Conditions		Temperature (°C)	Pressure (MPa)	Enthalpy (kJ/kg)	Power (kW)	%
Air heater	in	25	-	-	23,320	7.34%
	out	200				
Economizer	in	240	15.0	1,039	48,148	15.15%
	out	330	14.7	1,520		
Evaporator	in	340	14.7	1,598	106,454	33.49%
	out	340	14.7	2,620		
Superheater I	in	340	14.7	2,620	58,326	18.35%
	out	434	14.1	3,123		
Superheater II	in	402	14.1	3,006	42,024	13.22%
	out	540	13.6	3,439		
Reheater	in	357	3.2	3,128	39,623	12.46%
	out	535	3	3,536		
Total					317,895	100%

Electric Power, Heat Rate and Efficiency

Vojany I Unit 1 was built for the sole purpose of generating electric power. This makes the evaluation of electricity output a priority. A turbine with both high and low pressure stages, operating at 85% efficiency was assumed for Unit 1. In addition, the steam turbine is coupled to a 95% efficiency generator. Lastly, a condensing temperature of 65 °C was assumed. The available information concerning temperature and pressure of steam at the turbine inlet and at the reheater inlet allows the calculation of the real drop in enthalpy for the high pressure turbine. In the case of the low pressure turbine, where an isentropic process is assumed, the drop of enthalpy from the steam in the turbine is calculated as it follows:

$$\eta_{turbine} = \frac{\Delta h_{real}}{\Delta h_{isentropic}} \quad (8)$$

In equation 8, h represents enthalpy and η stands for efficiency. Following, the estimation of electricity output must account for both turbine stages and the generator efficiency, as described in equation 9.

$$Electricity\ Output = (\Delta h_{turbine,HP} + \Delta h_{turbine,LP}) * \dot{m}_{steam} * \eta_{generator} \quad (9)$$

Table 13 examines both the high and low pressure points of expansion and the inherent change in enthalpy of the working fluid to quantify the proportion in which thermal energy is converted

into electric power.

Table 13. Electrical output

HP Turbine point of expansion		
Enthalpy of main steam	kJ/kg	3,439
Condensing pressure	MPa	3.20
Condensing temperature	°C	357
Condensing enthalpy	kJ/kg	3,128
Steam enthalpy decrease in turbine	kJ/kg	264
LP Turbine point of expansion		
Condensing temperature	°C	65
Enthalpy of steam	kJ/kg	3,536
Entropy of steam	kJ/kg.K	7.34
Condensing pressure	MPa	0.03
sg	kJ/kg.K	7.83
sf	kJ/kg.K	0.89
Vapor Quality		0.93
Condensing enthalpy	kJ/kg	2,450
Steam enthalpy decrease in turbine	kJ/kg	922.63
Electrical Output	MWe	109.58

The calculation of heat rate provides another valuable parameter to evaluate power plant performance. It measures the fuel needed to generate a unit of sellable electricity. Furthermore, it is inversely proportional to the overall efficiency. Heat rate can be defined by the following equation (Stultz & Kitto, 2005):

$$\text{Heat Rate} = \frac{\text{Fuel flow} * \text{LHV}}{\text{Electrical Output}} \quad (10)$$

The boiler efficiency is a measure of the efficacy in which heat product of fuel combustion is transferred to the working fluid. It can be defined according to equation 11.

$$\eta = \frac{Q_{abs}}{Q_{in}} \quad (11)$$

Where η is boiler efficiency, Q_{abs} is the heat transferred to steam and Q_{in} is the energy input to the boiler. For Unit 1, the heat to steam is expressed as the sum of superheated steam, re-heated steam and blowdown. On the other hand, energy input is represented by the heat content of fuel and preheated air.

$$\eta = \frac{Q_{SH} + Q_{RH} + Q_{BD}}{LHV * \dot{m}_{fuel} + Q_{air}}$$

According to Vakkilainen & Ahtila (2011) this direct method to calculate the boiler efficiency features simplicity at the cost of accuracy, since it neglects some significant energy flows such as feedwater preheating, sootblowing and attemperation. Table 14 presents an account of the energy inputs and outputs necessary to calculate the boiler efficiency using the direct method.

Table 14. Boiler efficiency

Heat to steam (kW)	
Main Steam	233,272
Reheated Steam	39,623
Blowdown	268
Heat Input (kW)	
Fuel	298,795
Preheated air	23,320
Boiler Efficiency (direct method)	84.80%
Heat Rate (kJ/kWh)	9,818.5

Flue Gas Temperature Profile

The flue gas-side path starts in the furnace, where fuel and air react to release heat. Next, the resulting flue gases reach the first superheater, followed by a second superheater and a reheater. After that, in the back pass section of the boiler, flue gases flow through the economizer and the air preheater. A diagram of the disposition of heat exchangers throughout the boiler in Unit 1 is displayed on Figure 23.

The flue gas temperature profile can be estimated using energy balances, given the fact that heat absorbed by the working fluid ought to match the energy provided by the flue gas. Since the flue gas exit temperature was set at 150°C, calculations must start from this point. Additional values will be obtained backwards, following equation 7. Next, heat balance for the air heater is shown.

$$Q_{Air\ Preheater} = \dot{m}_{FG} * C_{p_{GF}} * (T_{FG,in} - 423\ K)$$

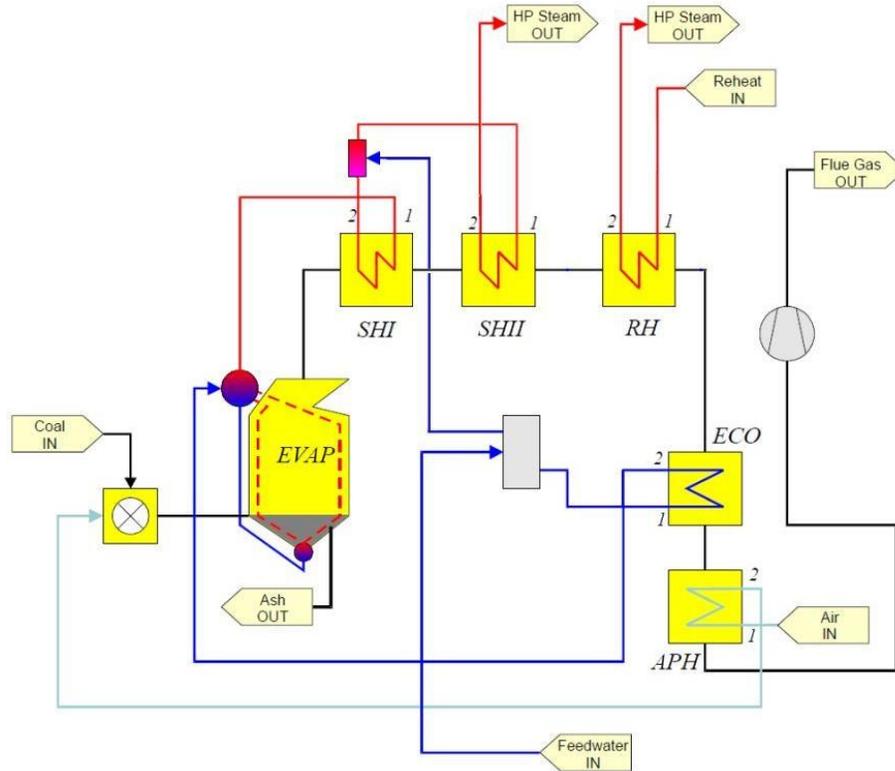


Figure 23. Heat exchangers in Unit 1. Modified from (Teir & Kulla, 2002)

Once more, an iterative process is needed to determine the specific heat of flue gases. Nevertheless, for the sake of simplicity and due to the subtle variation in the coefficients, values for specific heat were set in predefined ranges, as shown on Table 15.

Table 15. Specific heat of flue gases

FG Temperature (°C)	Enthalpy (kJ/kg)	Cp (kJ/kg.K)
1400	1,692	1.345
1300	1,558	1.331
1200	1,424	1.314
1100	1,293	1.297
1000	1,163	1.277
900	1,035	1.256
800	910	1.234
700	786	1.209
600	665	1.183
500	547	1.156
400	431	1.126
300	319	1.096
200	209	1.063
100	103	1.029

It should be noted that the proposed method for determining the flue gas temperature profile is a steady-state analysis, therefore not suitable for the evaporator section. Combustion is a transient process, meaning that fuel particles do not burn instantaneously and heat release is gradual. For this reason, values were assumed for the evaporator flue gas inlet and outlet. Considering that Unit 1 burns high-grade coal, Van Loo & Koppejan (2008) estimate that maximum temperatures in the area surrounding burners, typical of PFC boilers, reach 1650 °C. However, this value may not be representative of the flue gas behavior of a coal furnace. Computational fluid dynamics analysis reveal that except for the area adjacent to the burners, flue gas temperature is more or less constant throughout the furnace (Eirgrid, 2013; Lundström, 2008); hence, it can be assumed that no significant temperature variation takes place between the inlet and the outlet of the evaporator. Table 16 shows the estimated flue gas temperature profile following the aforementioned calculation approaches.

Table 16. Flue gas temperature profile

Flue Gas Temperature		Theoretical Temperature	Real temp
Evaporator	in	2,012	1,400
	out	1,389	1,389
Superheater I	in	1,389	1,389
	out	1,047	1,047
Superheater II	in	1,047	1,047
	out	801	801
Reheater	in	801	801
	out	569	569
Economizer	in	569	569
	out	287	287
Air Heater	in	287	287
	out	150	150

Figure 24 depicts the flue gas temperature profile as a function of the heat load. The Ideal or adiabatic-combustion curve represents the theoretical temperature behavior resulting from the steady-state calculation approach. Likewise, the FG curve shows a more realistic behavior in the change of flue gas temperature across the different sections of the boiler. In addition, the figure also shows the working fluid temperature in the heat exchangers.

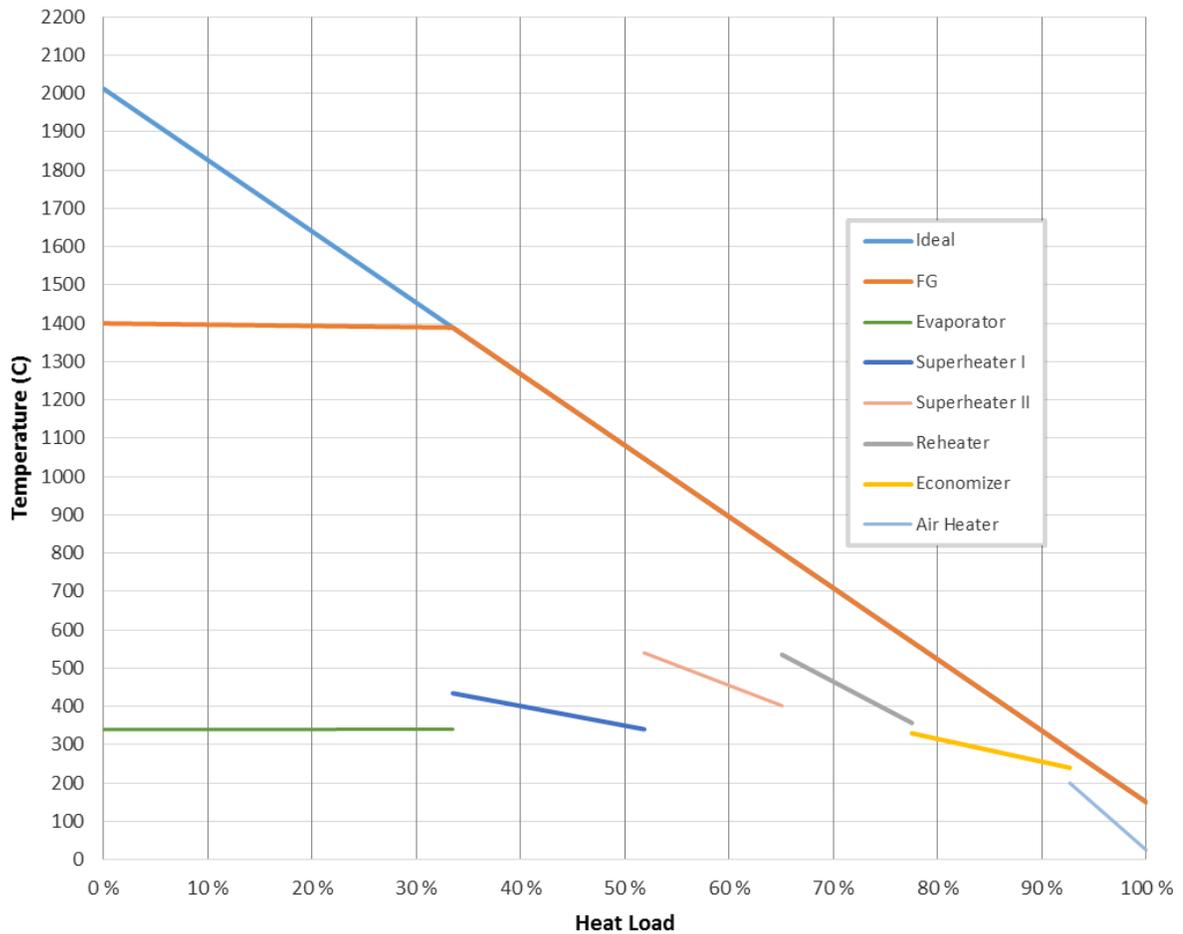


Figure 24. Flue gas and heat exchangers versus heat load

Dimensioning of Heat Transfer Surfaces

Once that temperature profile and heat loads have been determined, heat transfer surface can be estimated using equation 12. However, certain parameters have to be either assumed or calculated first.

$Q = U * A * LMTD$	(12)
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In the first place, transferred heat Q is already known. In addition, the Log Mean Temperature Difference is an expression of the disparity between the flue gas and the working fluid. Also, the global heat transfer coefficient U encompasses internal and external convection and radiation. Lastly, A represents the required heat transfer area.

Tube Dimensioning

The first step in the dimensioning of the pipework is the selection of tubes, based on industry standards. According to Rayaprolu (2009), typical values for tube external diameter (OD) for superheaters are 50.8 and 63.5 mm. The former was chosen, with an average thickness (THK) of 3.2 mm. The same considerations apply to the reheater. In the case of the evaporator, tubes in modern furnaces range from 38.1 to 76.2 mm OD. In order to keep pressure loss low, 76.2 mm OD tubes were selected with 5 mm THK. Moreover, heat transfer is increased with the utilization of small diameter tubes in the economizer. Ibid recommends tubes with 38.1, 44.5 or 50.8 mm OD. For the present study, 38.1 mm OD and 2.9 mm THK tubes were chosen for the economizer. Lastly, heat transfer area for the air preheater will not be calculated due to the inherent complexity associated with the analysis of compressible flow heat exchange.

Now that diameter and thickness for the different heat exchangers have been defined, internal tube diameter and tube cross sectional area can be estimated. Required cross sectional flow area can also be calculated, based on the working fluid mass flow, density and velocity. The working fluid flow velocities are assumed from typical values (Basu, 2006). Finally, the required number of tubes is calculated by dividing the required flow area by the tube cross sectional area. Obtained values for number of tubes are rounded up to an even number.

Table 17. Tube selection

Flow conditions	Units	Evaporator	Super-heater I	Super-heater II	Reheater	Economizer
Tube outside diameter	mm	76.2	50.8	50.8	50.8	38.1
Tube average wall thickness	mm	5	3.2	3.2	3.2	2.9
Tube velocity	m/s	2	18	19	20	1.125
Tube inside area	m ²	0.0034420	0.0015483	0.0015483	0.0015483	0.0008194
Number of plates	#	1	3	5	5	5
Spacing transverse	mm	304.8	203.2	203.2	203.2	152.4
Space longitudinal	mm	152.4	101.6	101.6	101.6	76.2
Length of heat exchanger	m	8				
st/D		4				
sl/D		2				

Average temperature	°C	340.2	387.5	471.0	446.0	285.0
Average pressure	MPa	14.7	14.4	13.9	3.1	14.8
Average density	kg/m ³	610	64	47	10	754
Average volumetric flow	m ³ /s	0.16	1.56	2.12	10.08	0.13
Area at design velocity	m ²	0.080	0.087	0.112	0.504	0.118
Number of tubes	#	24	57	73	326	145
Selected number of parallel tubes	#	24	19	15	66	29
Selected number of tubes	#	24	57	75	330	145
Surface width	mm	609.6	812.8	1,219.2	1,219.2	914.4
Flow area	m ²	4.27	5.28	7.72	7.72	5.79

Inside Convection Heat Transfer

Heat transfer by means of convection is correlated to the Nusselt number, as described in equation 13 (Stultz & Kitto, 2005).

$$Nu = \frac{\lambda_{conv} * D}{k} \quad (13)$$

Where λ_{conv} is the heat transfer coefficient; D is diameter and k is thermal conductivity of the fluid. In this first case, Nusselt within tubes is calculated using the empirical correlation (eq. 14) proposed by Gnielinski (2008).

$$Nu = 0.0235 * (Rn^{0.8} - 230) * (1.8 * Pr^{0.3} - 0.8) \quad (14)$$

$$Rn = \frac{\rho * v * D}{\mu} \quad (15)$$

$$Pr = \frac{\mu * C_p}{k} \quad (16)$$

Equation 14 requires the estimation of the Reynolds number (Re) and Prandtl number (Pr) for each section of the boiler. Nevertheless, this equation is not suitable for the estimation of the Nusselt number in the phase-change heat transfer mechanisms present in the evaporator. The

resistance to convective heat transfer inside tubes is known to be small, hence this coefficient will be assumed as 20,000 W/m².k (Vakkilainen, 2014). Table 18 shows the fluid properties and the results for inside convection coefficient throughout the boiler.

Table 18. Inside convection heat transfer coefficient

Inside Convection	Units	Evapo- rator	Super- heater I	Super- heater II	Re- heater	Econo- mizer
Viscosity	Pa.s	7.04E-005	2.43E-005	2.79E-005	2.64E-005	9.42E-005
Density	kg/m ³	610	64	47	10	754
Heat capacity	kJ/kg	8.23	4.41	2.97	2.26	5.17
Thermal conductivity	W/m.K	0.461	0.080	0.078	0.063	0.584
Tube velocity	m/s	1.0	35.4	36.6	19.7	1.1
Internal Diameter	m	0.0662	0.0444	0.0444	0.0444	0.0323
Reynolds number		553,501	4,111,489	2,718,233	320,582	289,243
Prandtl number		1.2562	1.3445	1.0696	0.9506	0.8334
Nu		1,035	5,357	3,415	575	492
$\lambda_{convection, inside}$	W/m ² .K	20,000	8,408	5,222	709	7,544

Outside Convection Heat Transfer

In a similar fashion to inside convection heat transfer, outside convection requires the estimation of Nusselt number. While equations for Pr and Re remain the same, fluid dynamics of flue gases demand a different equation for Nusselt number. In addition, typical flue gas velocities are assumed, following typical values suggested by Rayaprolu (2009).

$$Nu = f_o * f_a * (0.3 + \sqrt{Nu_{laminar}^2 + Nu_{turbulent}^2}) \quad (17)$$

$$Nu_{laminar} = 0.664 * \sqrt{Rn} * \sqrt[3]{Pr} \quad (18)$$

$$Nu_{turbulent} = \frac{0.037 * Rn^{0.8} * Pr}{1 + 0.443 * Rn^{-0.1} * Pr^{2/3} - 1} \quad (19)$$

Where f_o and f_a are correction factors, defined by equations 20 and 21.

$$f_a = 1 + \frac{0.7 * (S_l/S_t - 0.3)}{(1 - \pi * D/4 * S_t)^{1.5} * (S_l/S_t + 0.7)^2} \quad (20)$$

$$f_o = \frac{1 + (NR - 1) * f_a}{NR} \quad (21)$$

S_t being transverse spacing, S_l longitudinal spacing and NR number of rows. Table 19 summarizes the results for outside convection heat transfer.

Table 19. Outside convection heat transfer coefficient

Outside heat transfer convection	Units	Evaporator	Super-heater I	Super-heater II	Reheater	Economizer
Flue Gas Velocity	m/s	25	25	24	23	19
Number of rows		10				
Average gas temperature	°C	1,395	1,218	924	685	428
Viscosity	Pa.s	5.90066E-05	5.43721E-05	4.68412E-05	4.03596E-05	3.24587E-05
Density	kg/m ³	0.217	0.243	0.302	0.378	0.517
Heat capacity	kJ/kgK	1.35	1.33	1.27	1.22	1.15
Thermal conductivity	W/m ² .K	0.105	0.097	0.081	0.067	0.050
Outside diameter	m	0.0762	0.0508	0.0508	0.0508	0.0381
Reynolds number		7,003	5,669	7,869	10,939	11,521
Prandtl number		0.759	0.748	0.738	0.737	0.739
Nu laminar		51	45	53	63	64
Nu turbulent		40	34	44	56	59
Nu one row		65	57	69	85	88
a		4				
b		2				
y		0.804				
fa		1.135				
fo		1.121				
Nu		73	64	78	95	98
$\lambda_{convection, outside}$	W/m ² .K	91	124	123	125	130

Outside Radiation

Radiation is the predominant heat transfer mechanism within a boiler. Luminous radiation is emitted by the flame and the tube walls. Meanwhile, non-luminous radiation is released by the dust particles suspended in the flue gases (Ganapathy, 1994). The basic equation for radiative heat transfer is presented next.

$$\lambda_{radiation} = \frac{Q_{rad,pipes}}{A * (T_{FG} - T_{pipes})} \quad (22)$$

However, the calculation of the radiative heat transfer coefficient demands the estimation of additional parameters that involve the heat transfer region and both emissivity and absorptivity of gas particles. These parameters are described using equations 23 to 28.

$$\frac{Q_{rad,w}}{A} = \frac{\epsilon_w}{\alpha_{GP} + \epsilon_w - \alpha_{GP} * \epsilon_w} * \sigma * (\epsilon_{GP} * T_{FG}^4 - \alpha_{GP} * T_w^4) \quad (23)$$

$$\alpha_{GP} = \epsilon_{GP} * \left(\frac{T_{FG}}{T_w}\right)^{0.45} \quad (24)$$

$$\epsilon_{GP} = \epsilon_{gas} + \epsilon_{particles} - \epsilon_{gas} * \epsilon_{particles} \quad (25)$$

$$\epsilon_{gas} = \frac{3967 - T_{gas}}{6667} * (1 - e^{-0.824(P_{H2O} + P_{CO2}) * L_{RD}}) + \frac{2391 - T_{gas}}{8692} * (1 - e^{-25.91(P_{H2O} + P_{CO2}) * L_{RD}}) \quad (26)$$

$$\epsilon_{particles} = 1 - \exp\left(\frac{-3 * X_p * L_{RD}}{2 * d_p * \rho_p}\right) \quad (27)$$

$$L_{RD} = \frac{3.6 * S_t * S_l - \frac{\pi * D_o^2}{4}}{2 * S_t + 2 * S_l - 4 * D_o + \pi * D_o} \quad (28)$$

Where σ represents the Stefan-Boltzmann constant, $5.6e^{-8}$ W/m².K; ϵ_w is the emissivity of the pipe walls, assumed as 0.8; α_{GP} is the combined absorptivity of flue gas and dust particles; T_{FG} and T_w are flue gas and pipe wall average temperatures in kelvin, respectively. Additionally, ϵ_{gas} is the emissivity of flue gas; P_{H2O} and P_{CO2} are the partial pressures of water and carbon dioxide present in the flue gas. Furthermore, $\epsilon_{particles}$ represents the emissivity of dust particles; X_p is the dust density, assumed as 0.005 kg/m³; d_p is the dust average diameter, set at 0.00012 m and ρ_p is the real dust density, with a value of 2,400 kg/m³. Lastly, L_{RD} is the radiative length in meters; S_t and S_l are the transverse and longitudinal pitch in meters. The results from the calculation of radiative heat transfer are presented in Table 20.

Table 20. Radiative heat transfer coefficient

Outside radiation	Units	Evapora- tor	Super- heater I	Super- heater II	Re- heater	Econo- mizer
Tube wall emissivity		0.8				
Number of rows		10				
Partial pressure of CO ₂	bar	0.14				
Partial pressure of H ₂ O	bar	0.08				
Gas dust density	kg/m ³	0.005				
Dust diameter	m	0.00012				
Dust density	kg/m ³	2,400				
Wall temperature	°C	340.2	387.5	471.0	446.0	285.0
Average gas temperature	°C	1,395	1,218	924	685	428
Stefan-Boltzmann constant	W/m ² .K ⁴	5.67E-08				
Radiative length	m	0.178	0.118	0.118	0.118	0.089
Emissivity of gas		0.1066	0.0914	0.1090	0.1233	0.1115
Emissivity of dust particles		0.0046	0.0031	0.0031	0.0031	0.0023
Emissivity of gas-dust		0.1108	0.0942	0.1117	0.1260	0.1136
Absorptivity of gas-dust		0.1737	0.1359	0.1384	0.1433	0.1258
Radiation per area	W/m ²	45,203	24,112	10,240	3,704	834
$\lambda_{\text{radiation}}$	W/m ² .k	43	29	23	16	6

Global Heat Transfer Coefficient

The global heat transfer coefficient combines both inside and outside convection, radiation and conductivity of the material used for the pipework. Equation 29 describes this relation.

$$U = \frac{1}{\frac{1}{\lambda_{\text{convection},i}} + \frac{1}{\lambda_{\text{convection},o} + \lambda_{\text{radiation}} + \frac{D_o}{k_{\text{steel}}} * \ln\left(\frac{D_o}{D_i}\right)}} \quad (29)$$

The selected value for thermal conductivity of steel is 43 W/m.K. The calculated global heat transfer coefficients for each heat exchanger are presented in Table 21.

Table 21. Local and global heat transfer coefficients

Global heat transfer coefficient	Units	Evaporator	Super-heater I	Super-heater II	Re-heater	Economizer
Global coefficient correction factor		0.9				
Thermal conductivity of steel	W/m.K	43				
Inside Convection	W/m ² .K	20,000	8,408	5,222	709	7,544
Outside Convection		91	124	123	125	130
Radiation		43	29	23	16	6
U _{global}		116	129	125	103	118

Heat Transfer Surface

Now that all parameters from equation 11 are known, the required heat transfer area can be estimated for the different sections of the boiler. Results are presented in Table 22.

Table 22. Required heat transfer area

Heat transfer surface	Units	Evaporator	Super-heater I	Super-heater II	Re-heater	Economizer
inlet dt	°C	1060	955	507	266	239
outlet dt	°C	1049	706	399	212	47
LMTD	°C	1,054	824	451	238	118
Required area	m ²	816	544	747	1613	3475
Required total tube length	m	3,407	3,410	4,680	10,108	29,036
Required length for one tube	m	141.98	59.82	62.39	30.63	200.25
Number of passes	#	17.75	7.48	7.80	3.83	25.03
Selected number of passes	#	18	8	8	4	26
Length of one tube	m	144	64	64	32	208
Total tube length	m	3,456	3,648	4,800	10,560	30,160
Total tube area	m ²	827	582	766	1,685	3,610

2. VOJANY I UNIT 1 PULVERIZED BIOMASS COMBUSTION

At this point, an adequate calculation model has been developed based on Unit 1's business as usual operation, using coal as fuel. In addition, all the relevant parameters associated to its operation have been estimated. Therefore, it is possible to proceed with the evaluation of the proposed technology. Section 6 discusses in general terms the necessary considerations for the shift to biomass in Unit 1.

An iterative process was utilized to obtain an optimal temperature profile, while maintaining

efficiency within acceptable levels. An appropriate temperature profile provides flue gases sufficiently cooled down from their origin in the furnace, until they leave the boiler after the air preheater. In addition, iterations also look to maximize the use of the available heat transfer area in Unit 1.

In accordance to similar conversion experiences observed around Europe, the parameter that plays a key role is the steam flow. It determines the mass balance of the boiler and consequently, the heat load of the heat exchangers. For this reason, the amount of steam was iterated until the conditions for the combustion of biomass were satisfied. Next is presented a summary of the results from the calculation of performance for Unit 1 using biomass.

Air Flow Rate

Table 23. Theoretical oxygen demand of biomass

Element	Dry ash free	Mass (kg)	MM (kg/kmol)	N (kmol)	O2 (kmol)
C	51.02%	0.4645	12	0.039	0.0387
H	7.54%	0.0686	1	0.068	0.0170
O	41.85%	0.3810	16	0.024	-0.0119
N	0.03%	0.0003	14	0.000	-
S	0.00%	0.0000	32	0.000	0.0000
Cl	0.00%	0.0000	35	0.000	-
H2O	9.00%	0.0819	18	0.005	-
Ash	0.40%	0.0036	-	-	-
Total	109.84%	1.000	128.550	0.135	0.04379

Table 24. Biomass combustion air demand

Component	Composition	N (kmol/kg fuel)	Mass (kg/kg fuel)
H2O	1.88%	0.005	0.09
O2	20.61%	0.053	1.68
N2	77.54%	0.198	5.54
Total Air (wet)	100%	0.255	7.305
Total Air (dry)	-	0.250	7.22

Flue Gas Flow Rate

Table 25. Biomass combustion flue gas production

Component	N (kmol/kg fuel)	%	Mass (kg/kg fuel)
CO2	0.039	13.4%	1.70
H2O	0.043	15.0%	0.78

SO2	0.000	0.0%	0.00
N2	0.198	68.5%	5.54
O2	0.009	3.0%	0.28
Total Flue gas (wet)	0.289	100.0%	8.30
Total flue gas (dry)	0.245		7.52

Steam and Feedwater Flow Rate

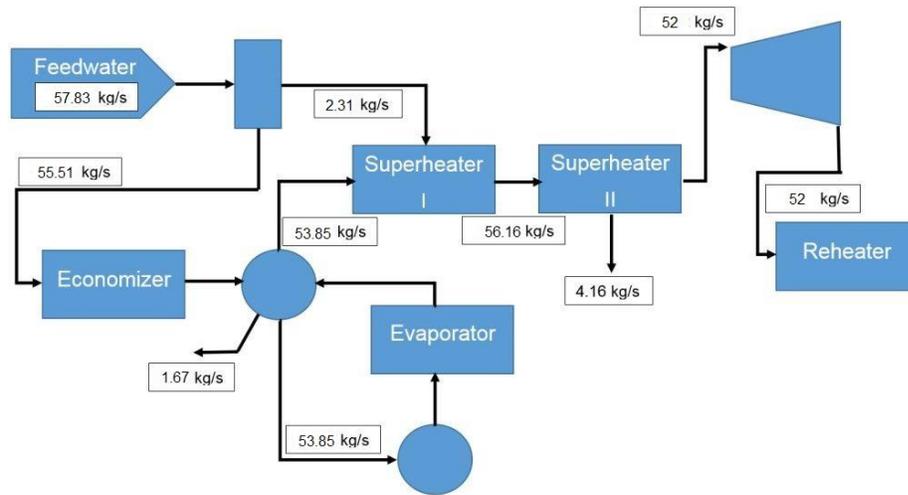


Figure 25. Resulting feedwater/steam mass flows

Steam/Water Conditions

Table 26. Resulting steam/water conditions

Steam/Water Conditions		Temperature (°C)	Pressure (MPa)	Enthalpy (kJ/kg)	Power (kW)	%
Air heater	in	25	-	-	5,825	3.48%
	out	90				
Economizer	in	240	15.0	1,039	26,672	15.93%
	out	330	14.7	1,520		
Evaporator	in	340	14.7	1,598	58,971	35.22%
	out	340	14.7	2,620		
Superheater I	in	340	14.7	2,620	32,310	19.30%
	out	434	14.1	3,123		
Superheater II	in	402	14.1	3,006	22,477	13.42%
	out	540	13.6	3,439		
Reheater	in	357	3.2	3,128	21,193	12.66%
	out	535	3	3,536		
Total					167,448	100%

Electricity Output and Heat Rate

Table 27. Electrical output for biomass combustion

HP Turbine point of expansion		
Enthalpy of main steam	kJ/kg	3,839
Condensing pressure	MPa	3.20
Condensing temperature	C	357
Condensing enthalpy	kJ/kg	3,128
Steam enthalpy decrease in turbine	kJ/kg	264
LP Turbine point of expansion		
Condensing temperature	C	65
Enthalpy of steam	kJ/kg	3,536
Entropy of steam	kJ/kg.K	7,34
Condensing pressure	MPa	0,03
sg	kJ/kg.K	7,83
sf	kJ/kg.K	0,89
Vapor Quality		0,93
Condensing enthalpy	kJ/kg	2,450
Steam enthalpy decrease in turbine	kJ/kg	922,63
Electrical Output	MWe	58,61

Boiler Efficiency

Table 28. Resulting efficiency

Heat to steam (kW)	
Main Steam	124,770
Reheated Steam	21,193
Blowdown	148
Heat Input (kW)	
Fuel	195,988
Preheated air	5,825
Boiler Efficiency (direct method)	72.40%
Net Heat Rate (kJ/kWh)	1,2038.3

Flue Gas Temperature Profile

Table 29. Specific heat of biomass combustion flue gases

FG Temperature (°C)	Enthalpy (kJ/kg)	Cp (kJ/kg.K)
1400	1,767	1.4145
1300	1,625	1.3971
1200	1,485	1.3783
1100	1348	1.3579
1000	1,212	1.3360
900	1,078	1.3125
800	947	1.2875
700	818	1.2610
600	692	1.2329
500	569	1.2034
400	449	1.1723
300	331	1.1396
200	217	1.1054
100	107	1.0699

Table 30. Flue gas temperature profile for biomass combustion

Flue Gas Temperature		Theoretical Temperature	Real temp
Evaporator	in	1,563	1,150
	out	1,097	1,097
Superheater I	in	1,097	1,097
	out	842	842
Superheater II	in	842	842
	out	664	664
Reheater	in	664	664
	out	497	497
Economizer	in	497	497
	out	286	286
Air Heater	in	286	286
	out	240	240

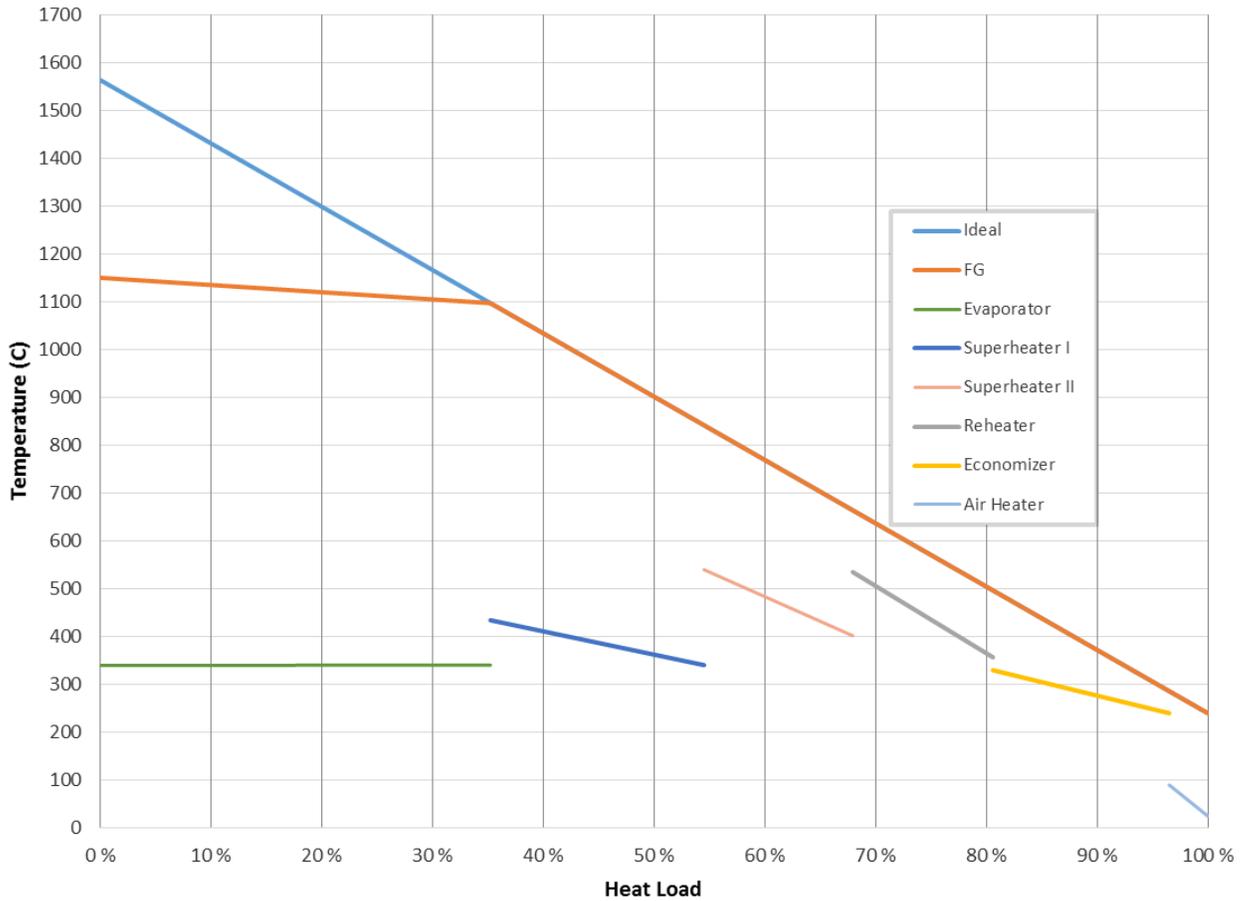


Figure 26. Resulting flue gas and heat exchangers versus heat load

Tube Dimensioning

Table 31. Tube selection

Flow conditions	Units	Evaporator	Superheater I	Superheater II	Reheater	Economizer
Tube outside diameter	mm	76.2	50.8	50.8	50.8	38.1
Tube average wall thickness	mm	5	3.2	3.2	3.2	2.9
Tube velocity	m/s	2	18	19	20	1.125
Tube inside area	m ²	0.003442	0.001548	0.001548	0.001548	0.000819
Number of plates	#	1	3	5	5	5
Spacing transverse	mm	304.8	203.2	203.2	203.2	152.4
Space longitudinal	mm	152.4	101.6	101.6	101.6	76.2
Length of heat exchanger	m	8				

st/d		4				
sl/d		2				
Average temperature	°C	340.2	387.5	471.0	446.0	285.0
Average pressure	MPa	14.7	14.4	13.9	3.1	14.8
Average density	kg/m ³	610	64	47	10	754
Average volumetric flow	m ³ /s	0.09	0.86	1.16	5.39	0.07
Area at design velocity	m ²	0.044	0.048	0.061	0.269	0.065
Number of tubes	#	13	32	40	175	80

Inside Convection Heat Transfer

Table 32. Resulting inside convection HT coefficient

Inside Convection	Units	Evaporator	Super-heater I	Super-heater II	Re-heater	Economizer
Viscosity	Pa.s	7.04E-005	2.43E-005	2.79E-005	2.64E-005	9.42E-005
Density	kg/m ³	610	64	47	10	754
Heat capacity	kJ/kg	8.23	4.41	2.97	2.26	5.17
Thermal conductivity	W/m.K	0.461	0.080	0.078	0.063	0.584
Tube velocity	m/s	1.0	34.9	37.4	19.9	1.1
Internal Diameter	m	0.0662	0.0444	0.0444	0.0444	0.0323
Reynolds number		566,058	4,056,942	2,775,718	323,343	290,413
Prandtl number		1.2562	1.3445	1.0696	0.9506	0.8334
Nu		1,054	5,300	3,473	579	494
$\lambda_{\text{convection, inside}}$	W/m ² .K	20,000	8,319	5,310	714	7,569

Outside Convection Heat Transfer

Table 33. Resulting outside convection HT coefficient

Outside heat transfer convection	Units	Evaporator	Super-heater I	Super-heater II	Reheater	Economizer
Flue Gas Velocity	m/s	25	25	24	23	19
Number of rows	#	10				
Average gas temperature	°C	1,124	969	753	580	391
Viscosity	Pa.s	5.19462E-05	4.79399E-05	4.20642E-05	3.69619E-05	3.07901E-05
Density	kg/m ³	0.251	0.282	0.342	0.411	0.528
Heat capacity	kJ/kgK	1.37	1.34	1.28	1.25	1.18
Thermal conductivity	W/m ² .K	0.096	0.087	0.073	0.061	0.049

Outside diameter	m	0.0762	0.0508	0.0508	0.0508	0.0381
Reynolds number		9,211	7,478	9,905	12,993	12,414
Prandtl number		0.744	0.744	0.741	0.750	0.749
Nu laminar		58	52	60	69	67
Nu turbulent		49	42	52	65	63
Nu one row		76	67	80	95	92
a		4				
b		2				
y		0.804				
fa		1.135				
f0		1.121				
Nu		86	75	89	106	103
$\lambda_{\text{convection, outside}}$	W/m ² .K	108	129	128	129	132

Outside Radiation

Table 34. Resulting radiative HT coefficient

Outside radiation	Units	Evapo- rator	Super- heater I	Super- heater II	Re- heater	Econo- mizer
Tube wall emissivity		0.8				
Number of rows		10				
Partial pressure of CO ₂	bar	0.13				
Partial pressure of H ₂ O	bar	0.15				
Gas dust density	kg/m ³	0.005				
Dust diameter	m	0.00012				
Dust density	kg/m ³	2,400				
Wall temperature	°C	340.2	387.5	471.0	446.0	285.0
Average gas temperature	°C	1,124	969	753	580	391
Stefan-Boltzmann constant	W/m ² .K ⁴	5.67E-08				
Radiative length	m	0.178	0.118	0.118	0.118	0.089
Emissivity of gas		0.1484	0.1269	0.1423	0.1546	0.1375
Emissivity of dust particles		0.0046	0.0031	0.0031	0.0031	0.0023
Emissivity of gas-dust		0.1524	0.1296	0.1450	0.1572	0.1395
Absorptivity of gas-dust		0.2206	0.1722	0.1675	0.1698	0.1509
Radiation per area	W/m ²	29,4614	15,006	5,949	2,068	686
$\lambda_{\text{radiation}}$	W/m ² .K	38	26	21	15	6

Global Heat Transfer Coefficient

Table 35. Resulting local and global HT coefficients

Global heat transfer coefficient	Units	Evaporator	Superheater I	Superheater II	Reheater	Economizer
Global coefficient correction factor		0.9				
Thermal conductivity of steel	W/m.K	43				
Inside Convection	W/m ² .K	20,000	8,319	5,310	714	7,569
Outside Convection		108	129	128	129	132
Radiation		38	26	21	15	6
U _{global}		125	133	128	106	120

Heat Transfer Surface

Table 36. Resulting HT area for biomass combustion

Heat transfer surface	Units	Evaporator	Superheater I	Superheater II	Reheater	Economizer
inlet dt	°C	810	663	302	129	167
outlet dt	°C	757	501	262	140	46
LMTD	°C	783	578	282	134	94
Required area	m ²	601	420	625	1,490	2,376